2016 Assessment of the ISO New England Electricity Markets

POTOMAC ECONOMICS

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PREFACE

Potomac Economics serves as the External Market Monitor for ISO-NE. In this role, we are responsible for evaluating the competitive performance, design, and operation of the wholesale electricity markets operated by ISO-NE.[1] In this assessment, we provide our annual evaluation of the ISO's markets for 2016 and our recommendations for future improvements. This report complements the Annual Markets Report, which provides the Internal Market Monitor's evaluation of the market outcomes in 2016.

We wish to express our appreciation to the Internal Market Monitor and other staff of the ISO for providing the data and information necessary to produce this report.

[1] The functions of the External Market Monitor are listed in Appendix III.A.2.2 of "Market Rule 1."

EXECUTIVE SUMMARY

ISO-NE operates competitive wholesale markets for energy, operating reserves, regulation, financial transmission rights ("FTRs"), and forward capacity to satisfy the electricity needs of New England. These markets provide substantial benefits to the region by coordinating the commitment and dispatch of the region's resources to ensure that the lowest-cost supplies are used to reliably satisfy demand in the short-term. At the same time, the markets establish transparent, efficient price signals that govern long-term investment and retirement decisions.

The ISO Internal Market Monitor ("IMM") produces an annual report that provides an excellent summary and discussion of the market outcomes and trends during the year.[2] The IMM Annual Report shows:

- Energy prices fell almost 30 percent in 2016 as natural gas prices fell by 34 percent. This correlation is consistent with our findings that the market performed competitively because energy offers in competitive electricity markets should track input costs.
- Average load was lower in 2016 by 2 percent as mild weather conditions prevailed during most of the year, particularly during the winter months.
- Low demand and surplus capacity in New England caused operating reserve shortages to be rare and contributed to low prices for both energy and ancillary services in 2016.
- Capacity prices remained low pool-wide at less than $4 per kW-month. Prices will be increasing to more than $7 per kW-month in the 2017/2018 planning year because of substantial retirements that occurred in FCA 8, which resulted in a capacity shortage and an administratively determined price. Prices in FCA 9 rose to $9.55, before falling to $7 and $5.30 in FCAs 10 and 11 as new resources entered and requirements fell.

The IMM report provides detailed discussion of these trends and other market results and issues that arose in 2016. This report is intended to complement the IMM report, evaluating the competitive performance of the market and focusing on key market design and competitive issues. Hence, this report includes:

- Competitive assessment of the energy and ancillary services markets;
- Evaluation of challenges facing the New England capacity market,
- Analysis of market issues related to out-of-market uplift costs, and
- Evaluation of the external transactions and the Coordinated Transaction Scheduling process established with New York.

2 See ISO New England's Internal Market Monitor 2016 Annual Markets Report, available at https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor.

Competitive Assessment

Based on our evaluation of the ISO-NE's wholesale electricity markets contained in this report, we find that the markets performed competitively in 2016. Our pivotal supplier analysis suggests that market power concerns remain in Boston and market-wide under high-load conditions. However, our analyses of potential economic and physical withholding indicates that the markets performed competitively with little evidence of significant market power abuses or manipulation in 2016. Market power concerns in Boston will be further alleviated when the Footprint Power combined-cycle plant comes into service in the very near future.

In addition, we find that the market power mitigation has generally been effective in preventing the exercise of market power in the New England markets, and was implemented consistent with Appendix A of Market Rule 1. The automated mitigation process helps ensure the competitiveness of market outcomes by mitigating attempts to exercise market power in the real-time market software before it can affect the market outcomes. To ensure competitive offers are not mitigated, generators can proactively request reference level adjustments when they experience input cost changes due to fuel price volatility and/or fuel quantity limitations. The implementation of the hourly offers in December 2014 has better enabled generators to submit offers that reflect their marginal costs and for the ISO to set reference levels that properly reflect these costs.

The only area where the mitigation measures may not have been fully effective is in their application to resources frequently committed for local reliability. Although the mitigation thresholds are tight, the suppliers have the incentive to operate in a higher-cost mode and receive higher NCPC payments as a result. Hence, we are encouraging the ISO to consider tariff changes as needed to expand its authority to address this concern.

Challenges to the New England Capacity Market

ISO-NE's capacity market was designed to maintain resource adequacy by attracting investment in installed capacity to satisfy summer peak conditions. While it has been successful in meeting this objective, four concerns have arisen in recent years that will need to be addressed with changes in the ISO-NE markets.

Addressing Winter Fuel Security Concerns

New England has become increasingly reliant on natural gas and vulnerable to disruptions in fuel supplies to the region. Over the decade from 2010 to 2020, 4 GW of oil and coal-fired capacity has retired or will retire, while the remaining oil and coal-fired capacity in New England will be economically challenged by falling capacity prices, the phase-in of PFP, and the entry of state-subsidized resources. The ISO has raised concerns regarding its increased reliance on natural gas and is currently evaluating these issues in a fuel-security study, which we believe is timely.

Although the oil storage capacity and LNG import capability are high enough to satisfy the demand for these fuels during a severe winter event, it would require very high utilization rates—far above any that have been observed in the past. Our fuel security assessment for a two-week severe winter period showed that while the system required 32 percent of this capability in the winter 2014/15, it is projected to require almost half of this capability in 2023. If New England were to suffer the largest pipeline contingency during these conditions, full utilization of its LNG and oil storage capability would not provide sufficient fuel to satisfy ISO-NE's electricity demands.

These trends raise questions about whether the current planning processes and market requirements are adequate to ensure fuel security by motivating generators to procure adequate fuel. Undoubtedly, ISO-NE's shortage pricing and PFP framework provides very strong incentives for suppliers to be available during such conditions. However, these conditions may be difficult to predict and may need to be explicitly recognized in the ISO's planning processes to ensure that the ISO can satisfy its one-in-ten reliability standard (i.e., the expectation that the ISO would involuntarily cut load no more than one time in 10 years).

The ISO's Winter Reliability Program ("WRP") has enhanced fuel security in recent winters by arranging for oil-fired, LNG-fired, and DR resources to procure the necessary fuel or be otherwise available during a ten-day cold spell. Thus, the WRP supported the ISO's seasonal reliability planning function by providing the ISO fuel procurement commitments from the generators. However, it did not create efficient incentives for other technologies that can satisfy ISO-NE's winter reliability needs. The WRP is scheduled to end by June 2018 when the PFP program becomes effective.

Hence, while PFP has the virtue of being technology neutral and will provide strong incentives for generators to procure the fuel that each believes is necessary to operate under severe winter conditions, it will not provide the planning and coordination that may be necessary to ensure that ISO-NE's seasonal reliability criteria are satisfied. Thus, the ISO should evaluate whether it has seasonal planning needs for the winter that must be met to satisfy its overall reliability criteria.[3] If so, we recommend that the ISO evaluate: a) the adequacy of the PFP framework in satisfying these needs, and b) the potential benefits and costs of market design changes that would complement PFP and facilitate the advance procurement of fuel needed to ensure fuel security.

Alternative Mechanisms to Accommodate State-Sponsored Resources

States are promoting certain public policies by subsidizing investment in individual generating facilities, which threatens to undermine the incentives for market-based investment. In our review of state initiatives to encourage development of renewable generation, we find that 5.7

3 In recognition of this concern, the ISO is studying fuel security issues. See description of the study at https://www.iso-ne.com/static-assets/documents/2017/05/20170522_fuel_security_study_update_final.pdf.

GW of nameplate capability with a capacity value of 1.9 GW is expected to enter in the next five FCAs. Given the current capacity surplus and the lack of growth in electricity demand, this disrupts the market by artificially depressing capacity and energy prices. This disruption will affect not only the markets and participants currently, but will raise costs for New England by adversely affecting participants' investment and retirement decisions for years to come.

Many of the New England state public policy initiatives have been justified as helping to reduce CO_2 and other emissions. However, employing market-based solutions to price emissions could achieve emission reductions at a lower cost than subsidies for specific classes of generation. In that regard, the Regional Greenhouse Gas Initiative ("RGGI") is a successful cap-and-trade market operating in the region that could be modified to address many of the states' goals. However, the New England states have expressed several concerns with relying on the RGGI market or any form of carbon pricing.[4] As a result, beginning in late 2016 we collaborated with ISO-NE to develop a mechanism for accommodating legitimate public policy investment while maintaining a well-functioning wholesale market that can still attract market-based investment.

The result of this collaboration is the Competitive Auctions with Subsidized Policy Resources ("CASPR"). This proposal recognizes the key issue – that the disruptive effects of out-of-market subsidies primarily result from the artificial short-term supply surpluses they create, which distort capacity and energy prices. Hence, CASPR would coordinate the entry of subsidized resources with retirements of existing resources to ensure that subsidized entry does not lead to artificial capacity surpluses. Under the CASPR proposal, subsidized resources that were subject to the MOPR and did not clear initially in the FCA could purchase the capacity obligation from a retiring resource or a new conventional resource to maintain the supply-demand balance.

The obligations would be purchased in a "substitution auction" conducted after the initial FCA auction, which would establish a clearing price for the substitution. Conventional new and retiring resources would be eligible for substitution by the subsidized resource, which would preserve the long-term balance of supply and demand. Including cleared new conventional resources is important for ensuring that the FCA does not facilitate inefficient investment.

Although there are other important details to this proposal, we believe this general approach strikes a reasonable balance between accommodating legitimate public policy initiatives and protecting the performance and viability of the RTO's wholesale electricity markets. We recommend the ISO examine the following issues as it moves forward with this proposal:

- The development of a settlement rule for conventional new resources in the substitution auction to provide efficient incentives and avoid potential manipulation concerns.
- ISO should consider whether to allow retirement offers into the substitution auction to be updated after the initial FCA, which will result in more efficient and competitive offers.

4 See NESCOE's April 7th, 2017 memo on "Feedback to NEPOOL on Long-Term "Achieve"-style IMAPP proposals", available at http://nepool.com/uploads/IMAPP_20170517_NESCOE_Memo_20170407.pdf.

Adjusting the MOPR to Reflect the Pay-For-Performance Framework

Under the pay for performance rules, most of the value of capacity in the long-run will be embedded in the performance payments. Participants that sell capacity are essentially engaging in a forward sale of the expected performance payments (i.e., they receive the capacity payment up front in exchange for not receiving the performance later when they are running during a shortage). However, resources that do not sell capacity can earn comparable revenues by simply running during shortages and receiving the performance payments. In other words, a supplier has two options:

- Sell capacity and commit to producing energy during shortages. Hence, the supplier relinquishes most of the performance payments it could have earned and will be charged (or credited) at the performance rate if it performs worse (or better) than average; or
- Do not sell capacity and earn performance payments by producing during the shortages.

In equilibrium, these two options should produce the same expected revenues. MOPR precludes an uneconomic entrant from selling capacity (choosing the first option), which simply means that the mitigated resource would default to option 2. Because option 2 should provide substantial expected revenues, the MOPR will not likely be an effective deterrent under the PFP framework.

Furthermore, the uneconomic entrant will be able to depress capacity prices without selling capacity because it will lower the expected number of shortage hours. A rational offer for capacity under PFP will include the foregone performance payments. Because the uneconomic entrant will reduce the expected frequency of shortages, it should lead capacity suppliers in the region to reduce their offer prices, which will lower capacity prices. Therefore, we would recommend the ISO make uneconomic units that were mitigated under the MOPR ineligible to receive performance payments. This recommendation may be needed to facilitate the effectiveness of the CASPR proposal discussed above.

Improving the Competitive Performance of the FCA

In our 2015 State of the Market Report, we evaluated the supply and demand in the FCA and concluded that:[5]

- Limited competition can enable a single supplier to unilaterally raise the capacity clearing price by a substantial amount.
- Publishing information on qualified capacity (new and existing) helps suppliers recognize when they can benefit by raising capacity prices.
- To the extent that the qualification process limits the number of new resources participating in the auction, the competitiveness of the auction will be reduced.

5 See *2015 Assessment of the ISO New England Electricity Markets*, Potomac Economics. https://www.iso-ne.com/static-assets/documents/2016/06/isone_2015_emm_report_final_6_14_16.pdf

To address these concerns, we identified market changes that could enhance competition in the FCA, including:

- Reducing any unnecessary barriers to participation, since this helps provide additional competitive discipline that reduces the incentive for a supplier to raise its offer substantially above its net CONE;
- Reducing the amount of information available on new and existing qualified resources before the auction to make it more difficult for a pivotal supplier to determine its profit-maximizing offer and encourage new suppliers to offer competitively at prices closer to their net CONE;[6] and
- Transitioning from the descending clock auction process to a sealed-bid auction to improve the competitiveness of the auction. This would eliminate information provided during the auction that can allow suppliers to determine when they are likely pivotal, which can enable them to set prices above competitive levels.

Causes and Allocation of NCPC Charges

Although the overall size of NCPC payments are small relative to the overall New England wholesale market, they raise a number of important concerns:

- They usually indicate that the markets do not fully reflect the needs of the system. Ultimately, this undermines the price signals that govern behavior in the day-ahead and real-time markets in the short-term and investment and retirement decisions in the long-term.
- NCPC payments can also distort suppliers' incentives. Thus, we evaluate the causes of NCPC payments to identify market improvements that would limit such distortions.
- NCPC payments tend to shift investment incentives away from flexible resources that will be increasingly valuable with the growth in intermittent renewable generation.

Our evaluation in this report shows that even with the improvements made in 2016, ISO-NE's uplift charges exceed the levels generated by most other RTOs. However, the ISO made substantial design improvements in early 2017 that should further reduce its NCPC, including allowing fast-start resources to set real-time energy prices and implementing interval-level (i.e., subhourly) settlements. Nonetheless, given the concerns that NCPC payments raise, we evaluate the causes of NCPC payments in order to identify potential market improvements.

6 The 2015 Annual Report identifies six types of information in addition to the Interconnection Queue that is published by the ISO that should be reviewed and modified as appropriate.

Day-Ahead NCPC Charges

In our assessment of day-ahead NCPC charges, we found that 70 percent was attributable to commitments for local second contingency protection, while 23 percent was attributable to commitments for the system-level 10-minute spinning reserve requirement. Although these requirements are reflected in the real-time market, there is no day-ahead market for operating reserves. Thus, generation committed in the day-ahead market to satisfy these requirements, the resulting costs are not reflected efficiently in day-ahead prices. This process resulted in:

- Excess commitments by the day-ahead market model for local second contingency protection in Boston, three-quarters of which would not have been needed under a co-optimized energy and reserve market.[7]
- Depressed clearing prices for energy and 10-minute spinning reserves providers. We estimate that additional generation was committed to satisfy the 10-minute spinning reserve requirement in almost half of all hours in 2016, although this was not reflected in energy prices or spinning reserve prices.

In addition, we continue to find that NCPC costs are inflated when the ISO is compelled to start combined-cycle resources in a multi-turbine configuration when its reliability needs could have been satisfied by starting them in a single-turbine configuration.

We make two recommendations to improve the pricing of energy and operating reserves.

- We recommend that the ISO co-optimize the scheduling and pricing of operating reserves with energy in the day-ahead market (i.e., determine the lowest cost set of offers that simultaneously satisfies energy demand and operating reserve requirements).
- We recommend the ISO expand its authority to commit combined-cycle units in a single-turbine configuration when that will satisfy its reliability need.

One advantage to co-optimizing the scheduling of energy and operating reserves in the day-ahead market is that it would facilitate the elimination of the forward reserve market. Nearly all of the resources assigned to satisfy forward reserve obligations continue to be fast-start resources capable of providing offline reserves. The forward reserve market should be eliminated because:

- It has not achieved its objective to lower NCPC by purchasing forward reserves from high-cost units frequently committed for reliability.
- The forward procurements do not ensure that sufficient reserves will be available during the operating day.

7 Note, this includes LSCPR units that were committed by a constraint in the day-ahead commitment model, while the majority of LSCPR units in Boston were determined before the day-ahead market.

- The obligation of forward reserve suppliers to offer at prices higher than the Forward Reserve Threshold Price can distort the economic dispatch and inefficiently raise costs.

For these reasons and because it biases the economic signals inefficiently, we recommend that ISO-NE eliminate the forward reserve market.

Real-Time NCPC Charges and Allocations

In assessing the real-time NCPC charges, we found that 5 percent were for local reliability and 9 percent were for system level capacity requirements, while the vast majority were associated with inconsistencies between the output of economically scheduled generators and clearing prices in the real-time market. Three of the four largest categories of real-time NCPC charges have been addressed by three significant market improvements implemented in 2016 or early 2017. These market improvements will not only lower real-time NCPC charges, but they will also result in much more efficient real-time prices that provide better performance incentives.

We also found that less than ten percent of the real-time NCPC can be attributed to real-time deviations, although they receive almost all of the allocated costs. Hence, we find that ISO-NE currently over-allocates real-time NCPC charges to virtual transactions and other real-time deviations. This has substantially reduced virtual trading activity and the overall liquidity of the day-ahead market. We recommend that the ISO modify the allocation of Economic NCPC charges to be more consistent with a "cost causation" principle, which would largely involve not allocating NCPC costs to virtual load and other real-time deviations that do not cause it. This recommendation is consistent with FERC's recent Notice of Propose Rulemaking related to uplift allocation, which we support.

External Interface Scheduling

New England's interconnections with adjacent systems provides considerable economic benefits and reliability benefits. Overall, 17 percent of New England's demand was satisfied by net imports, primarily from Canada. Although average imports were lower from New York, the size of the primary interface with NYISO allowed New England to import up to 1.4 GW in many hours with tight conditions in New England.

The lines from Canada are often fully utilized because of low generating costs in those areas, so it not difficult to maximize the utilization of the interfaces with Quebec and New Brunswick. Generating costs are more similar between New York and New England, making it more difficult to predict the optimal scheduled interchange between NYISO and ISO-NE. We find that market participants scheduled interchange in the profitable direction on average between NYISO and ISO-NE, netting $7 million in the day-ahead market. However, we still found that real-time interchange was scheduled in the unprofitable direction in 41 percent of intervals in 2016 and that market participants bear significant risk when scheduling in the CTS process.

Based on a detailed study of the performance of CTS scheduling process between New York and New England, we make the following findings:

- The amount of price-sensitive CTS bids offered at the NE/NY interface was significantly higher than the amount submitted at the PJM/NY interface, the primary reason why much larger savings were realized at this interface. The diminished liquidity at the PJM/NY interface is likely due to the large transactions fees imposed by NYISO and PJM.
- The CTS process has led to significant production cost savings, although less than half of the projected savings were actually realized, primarily because of price forecast errors.
- The price forecast errors are large enough that moving to Tie Optimization would result in *higher costs* rather than higher savings.
- We identify several factors that are likely contributing to poor forecasting:
  - The CTS scheduling model (which is administered by the NYISO) uses a simplified representation of the ISO-NE's forecast supply curve.
  - Both the NYISO and ISO-NE forecast models use ramp timing assumptions for interchange that are inconsistent with their respective dispatch models.

Although it is still early to draw strong conclusions, the results from the first year indicate a generally successful implementation of the CTS scheduling process between New England and New York. However, additional benefits will be realized if the ISOs can improve the accuracy of their price forecasts. Hence, we recommend that ISO-NE consider:

- Increasing the number of supply curve points that are used to model supply costs in the New England market, particularly in steep portions of the supply curve; and
- Modifying its real-time software to align ramp assumptions with actual ramp capability.

We have made similar recommendations to the NYISO to improve its forecasting.[8] We will continue monitor the performance of CTS and evaluate factors that contribute to forecast errors.

Table of Recommendations

We make the following recommendations based on our assessments of the ISO-NE's market performance. A number of these recommendations have been made previously and are now reflected in the ISO's Wholesale Market Plan.

8 See *2016 State of the Market Report for the New York ISO markets*, Potomac Economics, http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Reports/Market_Monitoring_Unit_Reports/2016/NYISO_2016_SOM_Report_5-10-2017.pdf

Recommendation	Wholesale Mkt Plan	High Benefit[9]	Feasible in ST[10]
Reliability Commitments and NCPC Allocation			
1. Modify allocation of "Economic" NCPC charges to make it consistent with a "cost causation" principle.	✓		✓
2. Utilize the lowest-cost fuel and/or configuration for multi-unit generators when committed for local reliability.			✓
Reserve Markets			
3. Introduce day-ahead operating reserve markets that are co-optimized with the day-ahead energy market.	✓	✓	
4. Eliminate the forward reserve market.			✓
External Transactions			
5. Identify improvements to the price forecasting that is the basis for Coordinated Transaction Scheduling with NYISO.		✓	✓
Capacity Market			
6. Evaluate changes in the availability or timing of information about qualified supply before the auction to improve competition in the FCA.			✓
7. Replace the descending clock auction with a sealed-bid auction.			✓
8. Evaluate potential benefits of market changes that would complement PFP to ensure fuel security under severe winter conditions.		✓	
9. Develop capacity market provisions that would accommodate legitimate public policy initiatives while preventing disruptive supply surpluses.		✓	
10. Modify performance payment eligibility for units subject to the MOPR to ensure it will continue to be effective.			✓

9 Recommendation will likely produce considerable efficiency benefits.

10 Complexity and required software modifications are likely limited.

I. Competitive Assessment of Energy Market

This section evaluates the competitive performance of the ISO-NE energy market in 2016, which is essential for LMP markets. Although LMP markets increase overall system efficiency, they may provide incentives for exercising market power in areas with limited generation resources or transmission capability. Most market power in wholesale electricity markets is dynamic, existing only in certain areas and under particular conditions. The ISO employs mitigation measures to prevent suppliers from exercising market power under these conditions. Although these measures have generally been effective, it is still important to evaluate the competitive structure and conduct in the ISO-NE markets because participants with market power may still have the incentive to exercise market power at levels that would not warrant mitigation.

Based on the analysis presented in this section, we identify the geographic areas and market conditions that present the greatest potential for market power abuse. We use a methodology for measuring and analyzing potential withholding that was developed in prior assessments of the competitive performance in the ISO-NE markets.[11] We address four main areas in this section:

- Mechanisms by which sellers exercise market power in LMP markets;
- Structural market power indicators to assess competitive market conditions;
- Potential economic and physical withholding; and
- Market power mitigation.

A. Market Power and Withholding

Supplier market power can be defined as the ability to profitably raise prices above competitive levels. In electricity markets, this is generally done by economically or physically withholding generating resources. Economic withholding occurs when a resource is offered at prices above competitive levels to reduce its output or otherwise raise the market price. Physical withholding occurs when all or part of the output of a resource is not offered into the market when it is available and economic to operate. Physical withholding can be accomplished by "derating" a generating unit (i.e., reducing the unit's high operating limit).

While many suppliers can increase prices by withholding, not every supplier can profit from doing so. Withholding will be profitable when the benefit of selling its remaining supply at prices above the competitive level is greater than the lost profits on the withheld output. In other words, withholding is only profitable when the price impact exceeds the opportunity cost of lost sales for the supplier. The larger a supplier is relative to the market, the more likely it will have the ability and incentive to withhold resources to raise prices.

[11] See, e.g., Section VIII, *2013 Assessment of Electricity Markets in New England*, Potomac Economics.

There are several additional factors (other than size) that affect whether a market participant has market power, including:

- The sensitivity of real-time prices to withholding, which can be very high during high-load conditions or high in a local area when the system is congested;
- Forward power sales that reduce a large supplier's incentive to raise prices in the spot market;[12] and
- The availability of information that would allow a large supplier to predict when the market may be vulnerable to withholding.

When we evaluate the competitiveness of the market or the conduct of the market participants, we consider each of these factors, some of which are included the analyses in this report.

B. Structural Market Power Indicators

This subsection examines structural aspects of supply and demand affecting market power. Market power is of greatest concern in areas where capacity margins are small, particularly in import-constrained areas. Hence, this subsection analyzes the three main import-constrained regions and all of New England using the following structural market power indicators:

- Supplier Market Share - The market shares of the largest suppliers determine the possible extent of market power in each region.
- Herfindahl-Hirschman Index ("HHI") - This is a standard measure of market concentration calculated by summing the square of each participant's market share.
- Pivotal Supplier Test - A supplier is pivotal when some of its capacity is needed to meet demand and reserve requirements. A pivotal supplier has the ability to unilaterally raise the spot market prices by raising its offer prices or by physically withholding.

The first two structural indicators focus exclusively on the supply side. Although they are widely used in other industries, their usefulness is limited in electricity markets because they ignore the demand for electricity that substantially affects the competitiveness of the market.

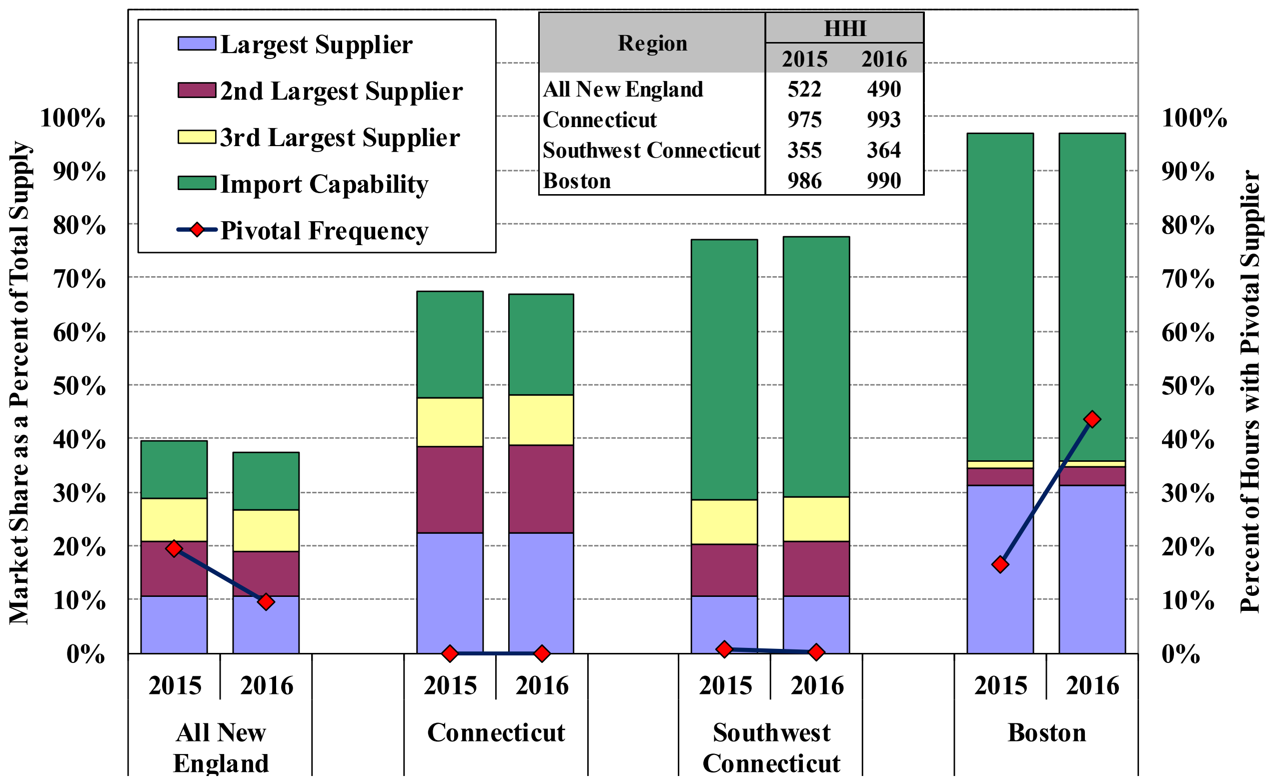
The Pivotal Supplier Test is a more reliable means to evaluate the competitiveness of energy markets because recognizes importance both supply and demand. Whether a supplier is pivotal depends on the size of the supplier and the amount of excess supply (above the demand) held by other suppliers. When one or more suppliers are pivotal, the market may be vulnerable to substantial market power abuse. This does not mean that all pivotal suppliers should be deemed to have market power. Suppliers must have both the *ability* and *incentive* to raise prices in order to have market power. For a supplier to be able to substantially raise energy prices, it must be able to foresee that it will be pivotal. In general, the more often a supplier is pivotal, the easier it

12 When a supplier's forward power sales exceed the supplier's real-time production level, the supplier is a net buyer in the real-time spot market, and thus, benefits from low rather than high prices. However, some incentive still exists because spot prices will eventually affect prices in the forward market.

is for it to foresee circumstances when it can raise clearing prices. For the supplier to have the incentive to raise prices, it must have other supply that would benefit from higher prices.

Figure 1 shows the three structural market power indicators for each of the four regions in 2015 and 2016. First, the figure shows the market shares of the largest three suppliers and the import capability in each region in the stacked bars.[13,14] The remainder of supply to each region comes from smaller suppliers. The inset table shows the HHI for each region. HHI values above 1800 are considered highly concentrated by the U.S. Antitrust Agencies. We assume imports are highly competitive so we treat the market share of imports as zero in our HHI calculation. The red diamonds indicate the portion of hours where one or more suppliers were pivotal in each region. We exclude potential withholding from nuclear units because they typically cannot ramp down substantially and would be costly to withhold due to their low marginal costs.

Figure 1: Structural Market Power Indicators
2015 – 2016



13 The market shares of individual firms are based on information in the monthly reports of Seasonal Claimed Capability("SCC"), available at: http://iso-ne.com/isoexpress/web/reports/operations/-/tree/seson-claim-cap. In this report, we use the generator summer capability in the July SCC reports from each year.

14 The import capability shown is the transmission limit from each year's Regional System Plan, available at: http://iso-ne.com/system-planning/system-plans-studies/rsp. The Base Interface Limit (or Capacity Import Capability) is used for external interfaces, and the N-1-1 Import Limits are used for the reserve zone.

Figure 1 indicates that the market share of the three largest suppliers in all New England fell from nearly 29 percent to less than 27 percent in 2016, primarily because Exelon sold the Granite Ridge Energy combined-cycle plant (700 MW) to Calpine Energy in early 2016. However, market concentration has changed very little in the three reserve zones. The largest suppliers had market shares ranging from 11 percent in Southwest Connecticut to 31 percent in Boston.

There is variation in the number of suppliers with large market shares. Boston has one supplier with a large market share, while Southwest Connecticut and all New England has three suppliers with comparable market shares. Because the import capability accounts for a significant share of total supply in each region (ranging from 11 percent in all New England to 61 percent in Boston), the market concentration in all of the areas is relatively low (i.e., less than 1000).[15]

However, these results do not establish that there are no significant market power concerns. These concerns are most accurately assessed under the pivotal supplier analysis, which indicates:

- In Southwest Connecticut and Connecticut, there were very few hours (< 0.5 percent) when a supplier was pivotal in 2016..
- In Boston, one supplier owned roughly 80 percent of the internal capacity, but was pivotal in 44 percent of hours in 2016. This underscores the importance of import capability into constrained areas in providing competitive discipline; and
- In all New England, a supplier was pivotal in 10 percent of hours in 2016.[16]

The pivotal frequency fell in all New England in 2016 because:

- Load levels fell 2.3 percent on average in 2016. Although load levels were modestly higher in Summer 2016, they were notably lower in other seasons, particularly in the winter because of much milder weather conditions; and
- Real-time market shares of the largest supplier fell because of the asset sales discussed above. Coal production from the largest suppliers' portfolio fell notably in the winter, reducing their real-time market share as well.

However, the pivotal frequency rose significantly in Boston in 2016 as the largest supplier changed its offer pattern and self-committed its combined-cycle units frequently in 2016. As a result, the average generation from these combined cycle units rose by 450 MW in 2016 and caused the supplier to be pivotal more frequently. In addition, planned transmission work was

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15 Antitrust agencies and the FERC consider markets with HHI levels above 1800 as highly concentrated for purposes of evaluating the competitive effects of mergers.

16 The pivotal supplier results are conservative for "All New England" compared to those evaluated by the IMM (see their 2016 SOM report, Section 3.7.3) primarily because of the following differences: (a) we assume no withholding from nuclear resources; (b) we do hourly pivotal supply evaluation (based on hourly averages) while the IMM does it at the UDS-level and counts an hour as a pivotal hour if a pivotal supplier exists in any of the UDS runs within that hour; and (c) headroom from units during their start-up and shut-down phases is not excluded from our evaluation .

more frequent in the Boston area during 2016, which reduced the import capability and caused the supplier to be pivotal more frequently for serving the needs of the load pocket.

The results in these regions warrant further review to identify potential withholding by suppliers in these regions. This review is provided in the following section, which examines the behavior of pivotal suppliers under various market conditions to assess whether the conduct has been consistent with competitive expectations.

C. Economic and Physical Withholding

Suppliers that have market power can exercise it by economically or physically withholding resources as described above. We measure potential economic and physical withholdi by using the following metrics:

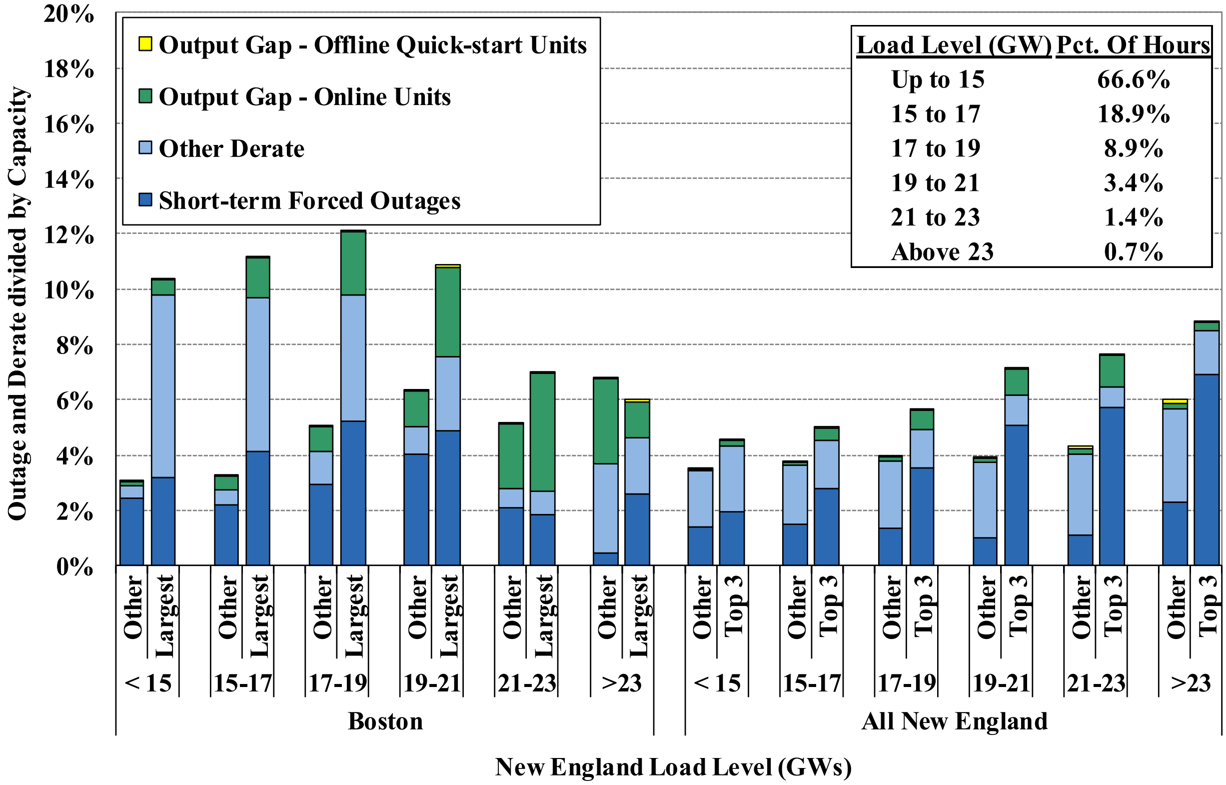
- Economic withholding: we estimate an "output gap" for units that produce less output because they have raised their economic offer parameters (start-up, no-load, and incremental energy) significantly above competitive levels. The output gap is the difference between the unit's capacity that is economic at the prevailing clearing price and the amount that is actually produced by the unit.[17] This may overstate the potential economic withholding because some of the offers included in the output gap may reflect legitimate supplier responses to operating conditions, risks, or uncertainties.
- Physical withholding: we analyze short-term deratings and outages because they are most likely to reflect attempts to physically withhold resources because it is generally less costly to withhold a resource for a short period of time. Long-term outages typically result in larger lost profits in hours when the supplier does not have market power.

The following analysis shows the output gap results and physical deratings relative to load and participant characteristics. The objective is to determine whether the output gap and/or physical deratings increase when factors prevail that increase suppliers' ability and incentive to exercise market power. This allows us to test whether the output gap and physical deratings vary in a manner consistent with attempts to exercise market power.

Because the pivotal supplier analysis raises competitive concerns in Boston and all New England, Figure 2 shows the output gap and physical deratings by load level in these two regions. The output gap is calculated separately for: a) offline quick-start units that would have been economic to commit in the real-time market (considering their commitment costs); and b) online units that can economically produce additional output. Our physical withholding analyses focus on: a) "Short-term Forced Outages" that typically last less than one week; and b) "Other Derates" that includes reductions in the hourly capability of a unit that is not logged as a forced or planned outage. The Other Derates can be the result of ambient temperature changes or other legitimate factors.

17 To identify clearly economic output, the supply's competitive cost must be less than the clearing price by more than a threshold amount - $25 per MWh for energy and 25 percent for start-up and no load costs.

Figure 2: Average Output Gap and Deratings by Load Level and Type of Supplier
Boston and All New England, 2016



The figure above shows the supplier's output gap and physical deratings as a percentage of its portfolio size in each region by load level. In Boston, we compare these statistics for the largest supplier to all other suppliers in the area. In all New England, we compare the top three suppliers, who collectively own one-third of internal resources, to all other suppliers.

In Boston, the amount of "Other Derate" in the largest supplier's portfolio was notably higher during low load periods. This was because its combined-cycle capacity was frequently offered and operated in reduced configuration during these periods (e.g., overnight hours). This is generally efficient and does not raise significant competitive concerns. In addition, the total amount of output gap and deratings generally fell as load levels increased to the highest levels, which is a good indication that suppliers tried to make more capacity available when the capacity needs were the highest.

Excluding the contributions of the "Other Derates" in Boston for the reasons described above, Figure 2 shows that although the overall output gap and deratings were not significant as a share of the total capacity in both Boston and all New England, the largest suppliers in each region exhibited a modestly higher level than other smaller suppliers in the region, particularly at higher load levels when prices are most sensitive to potential withholding.

In all New England, the total amount of output gap and deratings rose modestly as load levels increased to the highest levels. The increase for the largest suppliers was due primarily to higher short-term forced outages of several old coal and oil steam units on the hot summer days.

Overall, these results indicate that the market performed competitively and was not subject to substantial withholding in 2016.

D. Market Power Mitigation

Mitigation measures are intended to mitigate abuses of market power while minimizing interference with the market when it is workably competitive. The ISO-NE applies a conduct-impact test that can result in mitigation of a participant's supply offers (i.e., incremental energy offers, start-up and no-load offers). The mitigation measures are only imposed when suppliers' conduct exceeds well-defined conduct thresholds above a unit's reference levels and when the effect of that conduct on market outcomes exceeds well-defined market impact thresholds. This framework prevents mitigation when it is not necessary to address market power, while allowing high prices during legitimate periods of shortage.

The market can be substantially more concentrated in import-constrained areas, so more restrictive conduct and impact thresholds are employed in these areas than market-wide. The ISO has two structural tests (i.e., Pivotal Supplier and Constrained Area Tests) to determine which of the following mitigation rules are applied: [18,19]

- Market-Wide Energy Mitigation ("ME") – ME mitigation is applied to any resource that is in the portfolio of a pivotal Market Participant.
- Market-Wide Commitment Mitigation ("MC") – MC mitigation is applied to any resource whose Market Participant is determined to be a pivotal supplier.
- Constrained Area Energy Mitigation ("CAE") – CAE mitigation is applied to resources in a constrained area.
- Constrained Area Commitment Mitigation ("CAC") – CAC mitigation is applied to a resource that is committed to manage congestion into a constrained area.
- Local Reliability Commitment Mitigation ("RC") – RC mitigation is applied to a resource that is committed or kept online for local reliability.
- Start-up and No-load Mitigation ("SUNL") – SUNL mitigation is applied to any resource that is committed in the market.

There are no impact tests for the SUNL mitigation and the three types of commitment mitigation (i.e., MC, CAC, and RC), so suppliers are mitigated if they fail the conduct test in these three categories. This is reasonable because this mitigation is only applied to uplift payments, which

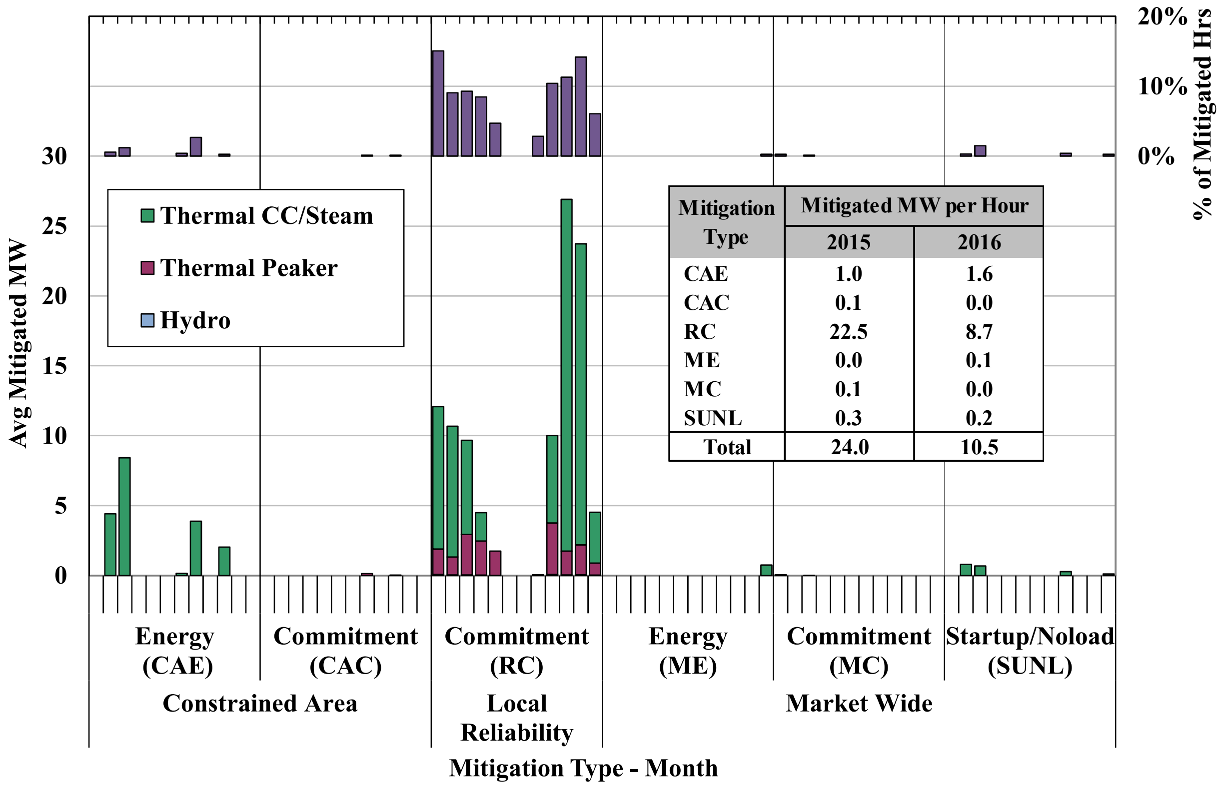
[18] See Market Rule 1, Appendix A, Section III.A.5 for details on these tests and thresholds.

[19] In addition, manual dispatch mitigation is applied to units dispatched OOM above their MinGen level.

will tend to rise substantially as offer prices rise so, in essence, the conduct test is serving as an impact test as well. When a generator is mitigated, all the economic offer parameters are set to their reference levels for the entire mitigated hour.

Figure 3 examines the frequency and quantity of mitigation in the real-time energy market. Any mitigation changes made after the automated mitigation process were not included in this analysis. The upper portion of the figure shows the portion of hours affected by each type of mitigation. If multiple resources were mitigated during the same hour, only one hour was counted in the figure. The lower portion of the figure shows the average mitigated capacity in each month (i.e., total mitigated MWh divided by total numbers of hours in each month) for each type of mitigation and for three categories of resources: hydroelectric units, thermal peaking units, and thermal combined cycle and steam units. The inset table shows the annual average amount of mitigation for each mitigation type in 2016.

Figure 3: Frequency of Real-Time Mitigation by Mitigation Type and Unit Type
By Month, 2016



The vast majority of mitigation in 2016 was local reliability commitment mitigation, which occurred in approximately 8 percent of hours and accounted for 83 percent of all mitigation. Mitigation in this category rose in October and November as a result of higher local reliability commitment in Boston because of planned transmission outages. This is consistent with the fact that local sub-areas raise the most significant potential market power concerns and are mitigated under the tightest thresholds. In general, this mitigation only affects NCPC payments and has little impact on LMPs.

Although the threshold for local reliability mitigation is tighter than the thresholds used for other mitigation, it is not fully effective because suppliers sometimes have the latitude and incentive to operate in a more costly mode and receive larger NCPC payments as a result. For example, combined-cycle units needed for reliability that can offer in a multi-turbine configuration or in a single-turbine configuration generally do not offer in the single-turbine configuration when they are likely to be needed for local reliability. By offering in a multi-turbine configuration, these units receive higher NCPC payments. Likewise, generators are sometimes not required to burn the lowest-cost fuel – e.g., a substantial amount of NCPC was paid in 2016 to a unit that usually burned oil when natural gas was much less expensive. We continue to recommend that the ISO consider tariff changes that would expand its authority to address these issues.

Not all local reliability mitigation was on units that were committed for reliability reasons. Some local reliability mitigation was on units that were committed economically, but started earlier or shut down later than their economic schedules would require (in accordance with operator instructions).[20] Most local reliability mitigation of thermal peaking units was of those that shut down later than scheduled. This mitigation typically occurred during start-up and shut-down periods and did not have substantial impact on LMPs or NCPC payments.

The amount of non-local-reliability mitigation has been low since the hourly offer market enhancement was implemented in December 2014. This allows suppliers to offer on an hourly basis and update their offers and fuel costs in real time. In addition to improving the competitiveness of the offers themselves, this change has improved the accuracy of the mitigation, particularly for:

- Energy limited hydro resources, whose costs are almost entirely opportunity costs (the trade-off of producing more now and less later). These costs are difficult to accurately reflect when only one single offer was allowed for the entire day.
- Oil-fired resources, which become economic when gas prices rise above oil prices, but have limited on-site oil inventory. The suppliers may raise their offer prices to conserve the available oil in order to produce during the hours with the highest LMP.
- Gas-fired resources during periods of tight gas supply. Volatile natural gas prices create uncertainty regarding fuel costs that can be difficult to reflect accurately in offers and reference levels. The uncertainty is increased by the fact that offers and reference levels must be determined by 2 pm on the prior day.

To supplement this improvement in offer flexibility, reference level adjustments should be made as necessary to account for the opportunity costs associated with these types of energy

[20] This was implemented by the ISO in December 2014 to address a potential gaming concern.

limitations. Appropriately recognizing these opportunity costs in resources' reference levels reduces the potential for inappropriate mitigation of competitive offers.

E. Competitive Performance Conclusions

The pivotal supplier analysis suggests that structural market power concerns remain in Boston and in all New England under high-load conditions. However, based on the analyses of potential economic and physical withholding, we find that the markets performed competitively with no significant evidence of market power abuses or manipulation in 2016. In addition, the market power concerns in Boston will be further alleviated when the Footprint Power combined-cycle plant comes into service in the very near future.

In addition, we find that the market power mitigations have generally been effective in preventing the exercise of market power in the New England markets. The automated mitigation process helps ensure the competitiveness of market outcomes by mitigating attempts to exercise market power in the real-time market software before it can affect the market outcomes. To ensure competitive offers are not mitigated, generators can proactively request reference level adjustments when they experience input cost changes due to fuel price volatility and/or fuel quantity limitations. The implementation of the hourly offers in December 2014 has better enabled generators to submit offers that reflect their marginal costs and for the ISO to set reference levels that properly reflect these costs.

The only area where the mitigation measures may not have been fully effective is in their application to resources frequently committed for local reliability. Although the mitigation thresholds are tight, the suppliers have the incentive to operate in a higher-cost mode and receive higher NCPC payments as a result. Hence, we are encouraging the ISO to consider changes that would expand it authority to address this concern.

II. FUTURE CHALLENGES IN THE NEW ENGLAND CAPACITY MARKET

The Forward Capacity Market (FCM) is designed to attract and maintain sufficient resources to satisfy ISO-NE's long-term resource planning requirements efficiently. FCM provides revenues that supplement the signals provided by the energy and ancillary services markets. In combination, these three sources of revenue provide critical signals that govern investment, retirement, and other long-term decisions made by market participants. Therefore, it is important to evaluate the sufficiency, competitiveness and any potential challenges to the capacity markets.

In Subsections A and B, we discuss the evolution of the resource mix in New England and evaluate the incentives for investment in new and existing generating capacity. In Subsections C and D, we discuss two key challenges for the capacity market:

- Maintaining fuel security as the region's reliance on natural gas grows, and
- Accommodating legitimate public policy investment without disrupting incentives for generation that is not subsidized.

The last two subsections discuss alternative approaches for advancing the various reliability, environmental, and cost objectives, and provide our conclusions and recommendations.

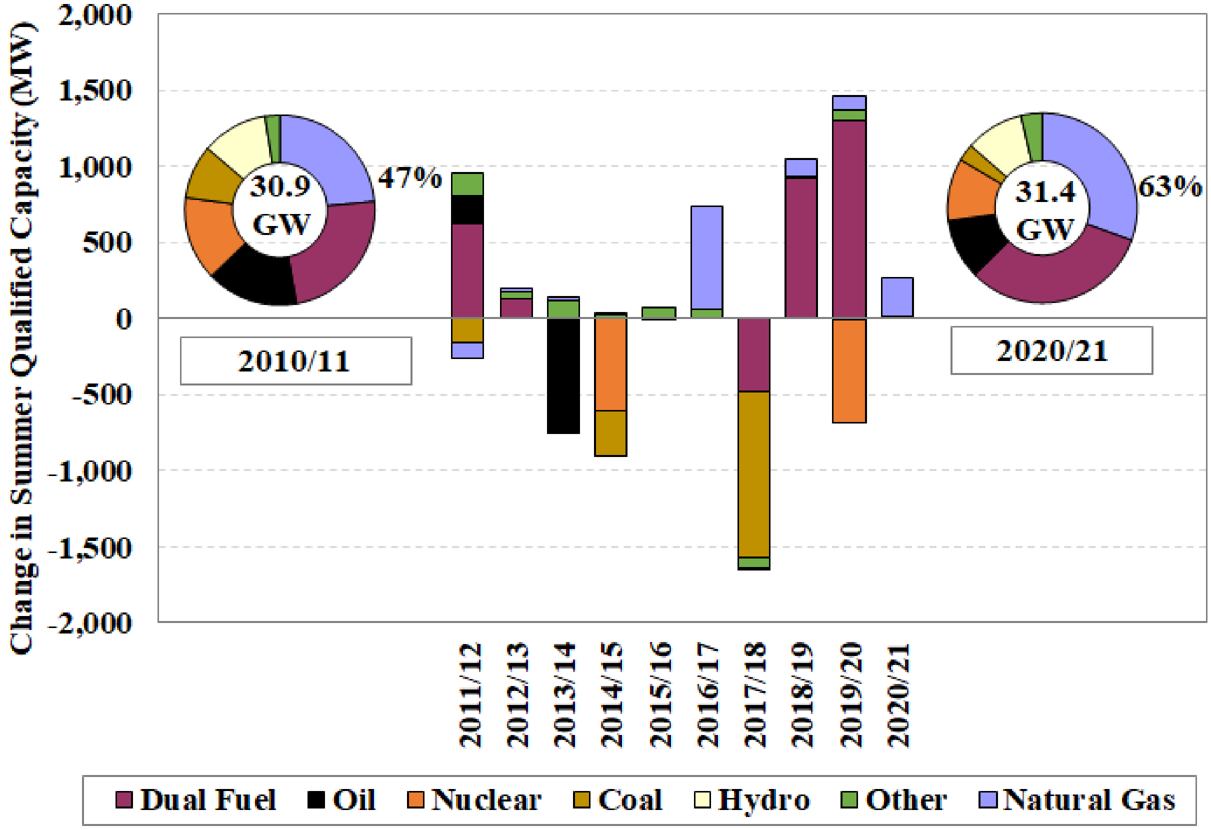
A. Evolution of New England's Resource Mix

A core objective of deregulation was to maintain reliability of the electric system at the lowest cost. The ISO-NE markets have generally performed well in this regard. From 2010/11 to 2020/21, the New England region has or will see a net increase of 500 MW in internal generation capacity. Due to the relative economics of natural gas-fired generation, over 4 GW of new fuel-efficient conventional generation has entered, while a comparable amount of nuclear, coal-fired, and older steam turbine capacity has retired. Over this period, consumer costs have generally declined.[21] The transition to a more fuel-efficient resource mix has also resulted in lower carbon emissions.

Figure 9 shows the change in the resource mix of the New England region over the decade from 2010/11 to 2020/21. The figure also shows the quantity and type of resources that have entered and exited the market during this timeframe. Although the region continues to see net increases in capacity, its resource mix has become substantially more reliant on natural gas. The share of resources relying on natural gas (gas-fired or dual-fuel) has risen from 47 percent to 63 percent over this timeframe. These changes in the resource mix raise potential fuel security issues that we discuss in Subsection C.

21 See slide 8 of ISO New England's *State of the Grid: 2017*, available at https://www.iso-ne.com/static-assets/documents/2017/01/20170130_stateofgrid2017_presentation_pr.pdf.

Figure 4: Trends in New England Resource Mix[22]
2010/11 – 2020/21



Before discussing the long-term challenges facing the ISO-NE markets, we first evaluate the long-term economic signals the markets are currently providing in the following subsection.

B. Incentives for Investment in Conventional and Renewable Generation

The net revenues earned by generators are defined as the total revenues that a generator would earn (from all market and non-market sources) less its variable production costs. Net revenues serve to cover a supplier's fixed costs and the return on its investment. Evaluating net revenues allows us to assess the performance of the market in providing efficient long-run economic signals and understand trends in the development and retirement of generating capacity.

Net Revenues for Conventional Generation

We estimate the net revenues from the ISO-NE markets for older existing and new gas-fired and dual-fuel units. The technologies we evaluate are:

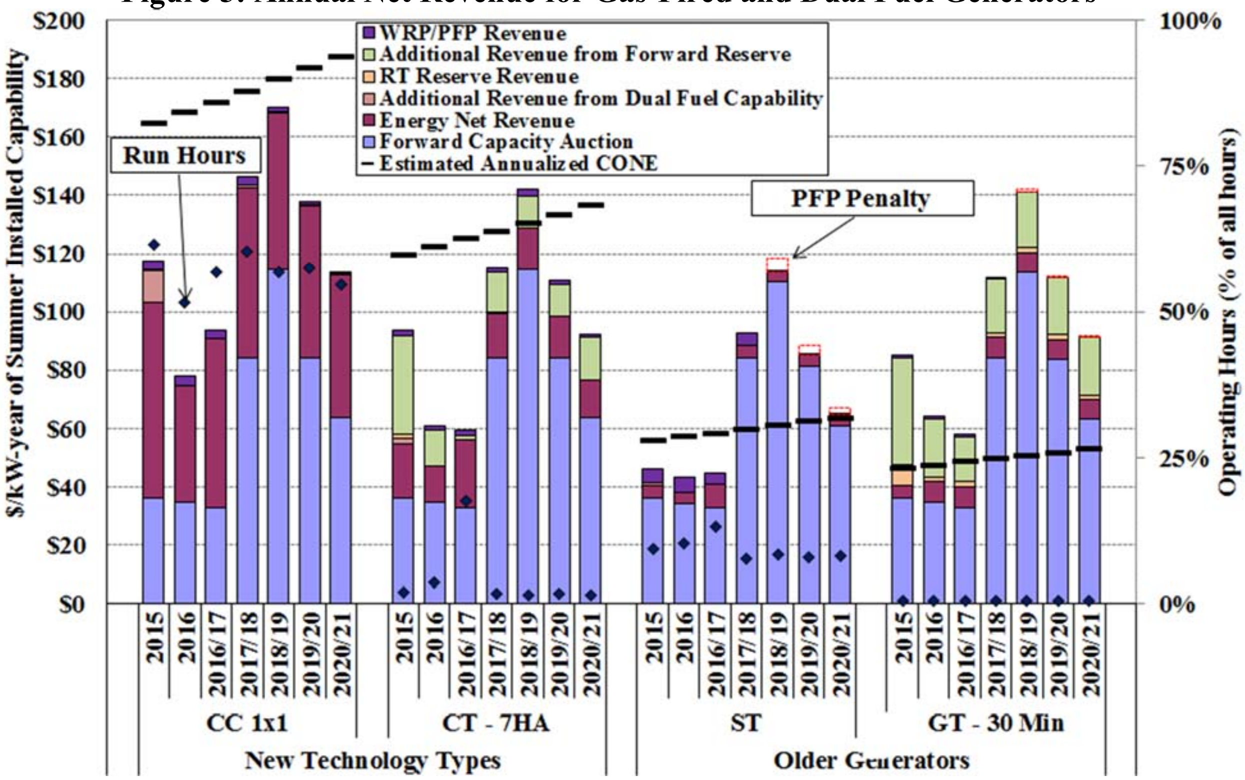
22 The generation capacities are based on the Summer Claimed Capabilities. The classification of generation as gas-fired, dual fuel or oil-fired is based on the fuels burned by the unit over the period.

- *Hypothetical new units*: (a) a 1x1 Combined Cycle ("CC") unit, and (b) a frame-type H-Class simple-cycle combustion turbine ("CT-7HA") unit; and
- *Hypothetical existing units*: (a) a Steam Turbine ("ST") unit, and (b) a 30-minute Gas Turbine ("GT-30") unit.[23]

We estimate net revenues under the two-settlement system by calculating net revenues based on day-ahead prices and schedules, but allowing gas turbines to be committed and dispatched based on the real-time prices. Deviations from day-ahead schedules are settled at real-time prices. A detailed list of assumptions and data sources is provided in the Appendix.

Figure 5 summarizes the net revenue estimates, as well as the levelized Cost of New Entry ("CONE") for new units or the Going Forward Costs ("GFC") for existing resources. The figure shows net revenues from each of the ISO's markets that a resource is capable of supplying. The revenues shown for the Forward Reserve market are only those that exceed the revenue that would be earned from selling energy, real-time operating reserves, and capacity. The figure also shows the additional revenues that units possessing dual-fuel capability would have earned.

Figure 5: Annual Net Revenue for Gas-Fired and Dual Fuel Generators[24]



23 Fuel costs are based on the Algonquin City Gates gas price index.

24 The CONE for fossil technologies are based on the recently filed ISO-NE CONE and ORTP study. The technology-specific average GFCs are based on estimates from the following study - *Renewable and Clean Energy Scenario Analysis and Mechanisms 2.0 Study* by NESCOE/ LEI.

Net revenues fell significantly from 2015 to 2016 for most technologies as falling natural gas prices led to lower energy prices, and relatively mild weather in 2016 led to lower peak demands. However, the increase in capacity prices and energy futures prices beginning in the 2017/2018 planning year will significantly increase the net revenues for all of the units shown. Starting in 2018/19, capacity revenue will be lower for steam turbines than for gas turbines and new generators because the PFP mechanism will be used to adjust capacity revenues based each generator's performance and availability during reserve shortages.

Profitability of New Units. Given the sustained low natural gas prices and the efficiency and emissions rates of the new gas-fired generators, these resources are likely to remain more economic than other conventional generators. Nonetheless, the current level of net revenues would not cover the entry costs of either type of new resource we evaluated. This is not unexpected given the capacity surplus that currently exists in New England and that existed when the capacity auction for the 2016/2017 Capacity Commitment Period was conducted.

The recent retirement of older steam turbines has reduced the ISO-NE capacity margin, leading to rising capacity prices from 2017/18 to 2020/21 and the entry of new gas-fired generation. While the reference unit (for estimating the capacity demand curve) would not recover its CONE based on forecasted net revenue in most years, actual entrants are likely to have specific advantages that make them more economic (e.g., existing onsite infrastructure, access to less expensive gas priced below the Algonquin index, or locating within a load pocket where prices are higher). The capacity margin has expanded in the last three years, increasing the gap between the estimated CONE and net revenue, which will make new entry less likely until additional retirements occur.

Profitability of Existing Units. Among older units, net revenues were highest for gas turbines primarily because they normally: a) have lower annualized GFCs than steam turbines and b) would expect to receive forward reserve revenues. Estimated net revenues for the existing gas turbines were generally higher than the average annualized GFC.

Steam turbines earn the vast majority of their net revenue from selling capacity. Given the low capacity prices before 2017, existing steam units' net revenues were unlikely to have been sufficient to cover the GFCs of a well-maintained steam unit in most areas. Hence, it is not surprising that 30 percent of the steam turbine capacity in service before 2010 has retired or plans to retire by 2017. With the increase in capacity prices after 2017, the remaining steam turbines will be more profitable in the near term.

Despite the fact that the average steam turbine and the average gas turbine are each shown to cover its costs through the 2020/21 Capacity Commitment Period, this is not true for all of the individual units in each of these categories. Some units that have higher-than-average GFCs or below-average performance will likely consider retirement if the prevailing prices continue.

Additionally, the reduction in capacity prices after 2020 in conjunction with the phase-in of the Pay-For-Performance ("PFP") capacity market rules from 2018 to 2024 presents significant challenges for steam units. PFP will shift more capacity revenue towards generators that are frequently online or available to start within 30 minutes. As the potential penalties for non-performance increase, oil, coal and gas steam turbines will expect lower net revenues and greater economic risk.[25] The retirement of steam turbines capable of running on coal or oil may raise reliability concerns during winter months that we discuss in Subsection C.

Incentives for Dual Fuel Capable Units. The ability to switch fuels away from natural gas can alleviate the fuel adequacy concerns during periods of severe winter weather. Figure 5 summarizes the net revenue estimates, as well as the levelized Cost of New Entry ("CONE") for new units or the Going Forward Costs ("GFC") for existing resources. The figure shows net revenues from each of the ISO's markets that a resource is capable of supplying. The revenues shown for the Forward Reserve market are only those that exceed the revenue that would be earned from selling energy, real-time operating reserves, and capacity. The figure also shows the additional revenues that units possessing dual-fuel capability would have earned.

Figure 5 shows that the additional revenues from the dual fuel capability were *de minimis* in 2016 and dropped significantly for all technologies because of the low gas prices and mild winter market conditions in 2016. Although the Winter Reliability Program ("WRP") provides units with sufficient revenues to maintain moderate inventories, the expected returns over the next three years are not (by themselves) sufficient for some units to build or retain the capability.[26] However, dual fuel capabilities provide a hedge against gas curtailment under tight supply conditions and would help augment the capacity revenues by reducing fuel-related outages once the PFP program becomes effective. Thus, investors in new and existing units may still prefer to install dual fuel capability, as evidenced by the relatively high share of dual fuel capable units among the new entrants in recent years.[27]

Incentives for Flexible Units. The integration of large quantities of intermittent renewable resources under the states' public policy initiatives will require a flexible resource base that can respond quickly to changes in net load. The current energy and reserve markets provide substantial incentives for generators to be flexible and available in real-time when clearing prices are likely to be high. For example, an older gas turbine that can start quickly and reliably

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25 The profitability of oil and coal steam turbines is likely to be worse than that of gas-fired units since natural gas is the cheaper fuel relative to coal and oil in the near future. In addition, coal units are also likely to incur additional environmental capex that existing gas-fired steam units may not require.

26 WRP also helps offset the auditing costs associated with commissioning dual fuel capabilities.

27 The ISO-NE CONE and ORTP Analysis also assumed that the reference technology for FCA-12 has dual fuel capability. See page 15 of Concentric Energy Advisors report, available at https://www.iso-ne.com/static-assets/documents/2016/11/a4_cea_cone_ortp_report_clean.docx.

provides off-line reserves would earn $13 to $39 per kW-year more net revenue than an older steam turbine. However, some of this net revenue is inflated by the Forward Reserve Market and would be significantly lower when and if this market is eliminated.[28]

As capacity margins fall and the financial impact of shortages increase under PFP, flexible units that can respond more effectively under these conditions will earn more net revenue. This additional revenue to flexible generation will increase as the PFP capacity market rules are phased-in from 2018 to 2024.

Additionally, real-time pricing reforms were implemented in early 2017 that will also help provide better incentives for flexibility. First, the fast start pricing rules will lead to higher more efficient prices during non-shortage conditions when peaking units must be deployed. Second, the sub-hourly pricing reforms will benefit fast-moving resources by settling based on their output and prices every 5 minutes. This replaces the previous hourly settlement system, which diluted the incentives for units to respond quickly to changes in system conditions.

Conclusions Regarding Conventional Resources. The New England fleet is shifting from older steam turbine capacity towards faster, more fuel-efficient combined cycle and peaking generation. However, the retirement of existing coal and oil-capable steam turbines raises concerns about the increasing reliance of the ISO-NE's system on natural gas. Furthermore, it is unclear from the net revenue analysis whether gas-fired generation will be motivated to install and maintain the capability to operate on a back-up fuel. We discuss these winter reliability concerns in Subsection C.

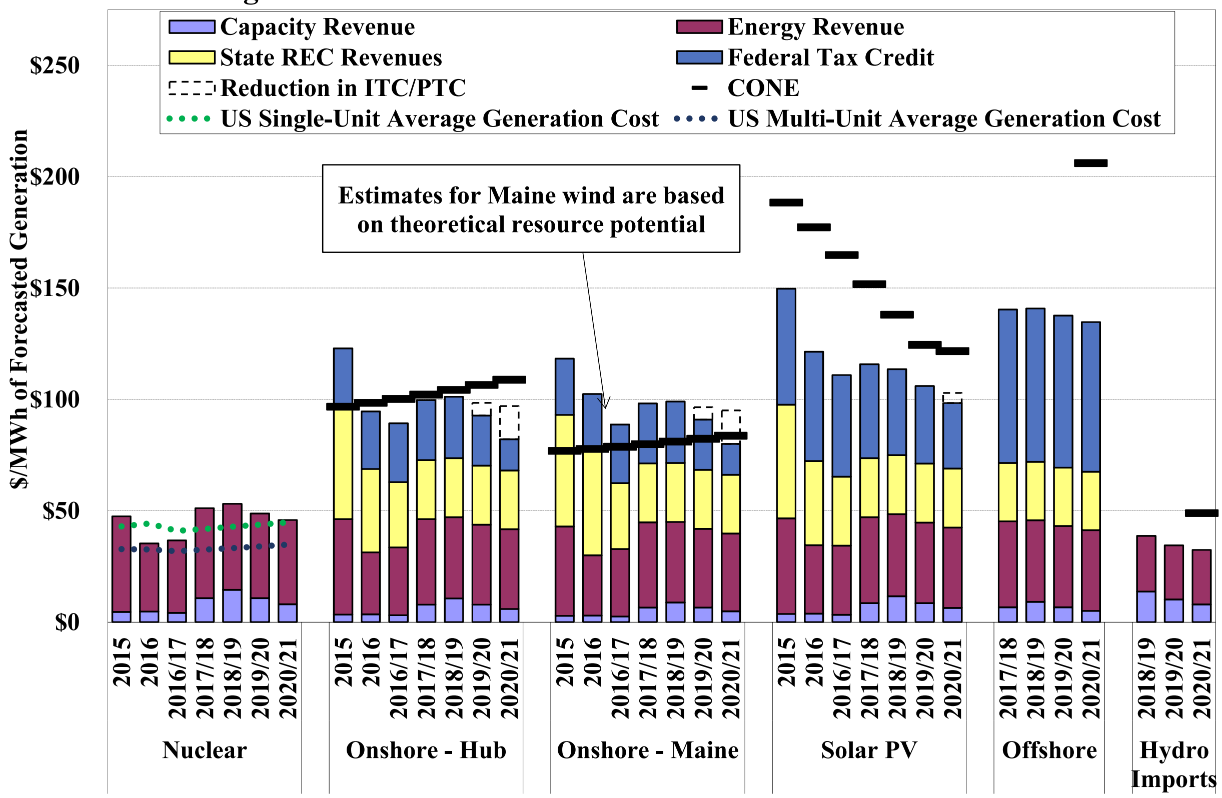
Net Revenues for Zero-Emission Resources

Due to the increasing public policy interest in reducing carbon emissions and increasing the penetration of clean energy, we estimate the net revenues for representative existing nuclear plants, hydropower imports from Canada, utility-scale solar PV, and onshore and offshore wind plants. These net revenues are estimated based on the prices at the New England Hub, but we also estimate the net revenues of a representative onshore wind plant located in Maine. For each technology, we estimate revenues from the ISO-NE markets and state and federal incentive programs. The assumptions are detailed in the Appendix.

Figure 6 summarizes the estimated net revenues for the calendar years 2015, 2016, and each Capacity Commitment Period from 2016/17 to 2020/2021. Energy prices for future periods are derived from OTC peak and off-peak futures. The figure also shows CONE estimates for new resources and average going forward costs (including O&M, fuel, and capex) for existing nuclear plants in the US.

[28] See Section III.F for our recommendations concerning Forward Reserve Market.

Figure 6: Annual Net Revenue for Zero-Emission Resources



Estimated revenues of nuclear and renewable plants from the ISO's energy market decreased markedly from 2015 to 2016. However, capacity and energy revenues are not projected to increase as substantially over the next few years because these technologies generally will not benefit as greatly from the increasing capacity prices. Intermittent renewable technologies are limited in the capacity they may sell while most net revenues for nuclear resources are derived from their margins in the energy market as discussed below.

Net Revenues for Nuclear Plants. Energy revenues constitute the majority (86 percent) of the revenue received by nuclear plants in 2016, much higher than all other technologies. Hence, expected energy prices (rather than capacity prices) play a dominant role in the decision to retire a nuclear unit. Consequently, the sharp decline in natural gas prices and associated reduction in energy prices have put substantial economic pressure on nuclear units throughout the country.

Our estimated net revenues of nuclear plants in ISO-NE generally exceeded the U.S. average generation costs for larger multi-unit plants for the periods shown, although estimated net revenues were lower than the U.S. single-unit average generation costs in 2016 and 2016/17. Operating costs for a plant in New England are expected to be moderately higher than the national average, and the decision to retire a nuclear plant also depends on the owner's long-term outlook and plant-specific factors that affect costs, financial hedges, and decommissioning costs and fund status.[29] Hence, such decisions over the next five years will be difficult to predict.

Net Revenues for Renewable Resources. New renewable units rely primarily on revenues from state and federal incentive programs. In 2016, over 60 percent of estimated net revenues for wind and solar units came from state and federal programs. From 2015 to 2016, REC prices and energy prices fell, reducing estimated net revenues for wind and solar units by 19 to 23 percent. The upcoming step-down of federal tax incentives is also likely to reduce the profitability wind and solar units starting around 2020.

Onshore wind plants appear to be the most economic of all renewable units, but their net revenues at the New England Hub are likely to be lower than its CONE from 2016 to 2020/21. The economics are likely to be better for a wind unit in Maine, but the output such units would be frequently reduced by transmission constraints out of Maine. These constraints have caused the actual capacity factors of recently built wind units in Maine to be 22 percentage lower than that of the hypothetical unit we studied. A number of developers have submitted proposals to expand the transmission capability from Maine under the Order 1000 proceedings and the state clean energy RFPs. The ISO has estimated the costs of these transmission lines to be in the range of 3.7 to 20 billion, depending on the total wind capacity in Maine. These new transmission costs are not included in the CONE for wind units in Maine.

Our results indicate that the net revenues of the hypothetical utility-scale solar PV unit we studied are likely to be insufficient to recover their estimated CONE through 2020/21. The investment costs for solar PV units are expected to drop significantly (>30 percent by 2019) in the near future. Therefore, the spread between the net revenues received by the utility-scale solar PV units and their CONE is likely to decrease.

Offshore wind plants have higher capacity factors and capacity values than their onshore counterparts. Consequently, the net revenues of these units are the highest on a $/kW-year basis among all the renewable units we studied. However, their estimated CONE is much higher than other renewable technologies and much higher than the estimated net revenues for these units.[30]

Profitability of Importing Hydropower from Canada. Hydro Quebec (“HQ”) relies primarily on hydropower capacity, and it is developing an additional 0.70 GW of hydro resources that are

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29 For instance, independent analysts have estimated the cost of generation for the Millstone plant to be in the $40-45/MWh range. This would reduce the Millstone plant’s revenue margin to eight percent in 2020/21, which is much lower than its margin of 34 percent in 2016, when the plant benefited from a price hedge (of $51.50 per MWh of energy) on its output. See 13th March, 2017 UBS note *US Electric Utilities & IPPs: Who's Up Next? Comparing the Nukes* and April 2017 report *Financial Assessment Millstone Nuclear Power Plant* by Energyzt Advisors, LLC.

30 The estimated CONE of offshore wind is particularly sensitive to the length of the undersea cable, which assumes approximately 40-mile undersea cable.

projected to be operational by 2020. Several developers have proposed building HVDC lines (each with a 1000MW+ capability) to import hydropower from HQ into New England. Like other renewable technologies, our analysis indicates that the net revenues for a developer of a representative HVDC line from HQ to the New England Hub is likely to be less than its estimated CONE. Therefore, the development of HVDC transmission from HQ likely requires state subsidies to be economic.

However, it is important to recognize that the economics of a given line are likely to be determined by project-specific factors. This factors include the route, the length of the line, the location of interconnection points, the extent to which the line is buried, the excess supply available in Quebec to export to New England, and the opportunity costs of HQ exporting to New York or Ontario.

Conclusions regarding Zero-Emissions Resources. New renewable units, existing nuclear units, and hydropower-backed imports provide carbon-free and non-gas based electricity that may be needed for achieving state public policy goals. With the exception of some nuclear plants, all of these technologies appear to be uneconomic without additional streams of revenues. Hence, several states have undertaken initiatives to further subsidize these resources. Depending on the timing and magnitude of these initiatives, they could result in artificial capacity surpluses in the short-term, which could distort long-term economic signals that are critical for ensuring resource adequacy.[31] We discuss the scope and potential approaches for addressing the issues caused by state-sponsored procurement in Subsection D. Based on our net revenue analysis, we estimate the cost of reducing carbon through these resources in Subsection E to illustrate the benefits of pursuing a technology-neutral, market-based approach to satisfy the states' objectives.

C. Fuel Security during Limited Natural Gas Supply Conditions

The previous subsections show investment trends that will increase New England's reliance on natural gas. Even as New England benefits from the low costs and environmental benefits of using natural gas, it will be important to consider fuel security, particularly during the winter when natural gas supplies are most limited.

ISO-NE has been concerned about its increasing reliance gas-fired generation for some time and is currently undertaking a study of its exposure to fuel security issues. This study is timely given the changes currently underway in the New England market. The analysis and recommendations in this section should complement the work currently underway by the ISO.

31 Addition of large quantities of intermittent resources is likely to lead to several operational challenges related to procurement of reserves, ramping and regulation. The ISO is studying the extent of these issues as part of its 2016 economic studies. See presentation *2016 Economic Studies – Phase II Scope of Work for Regulation, Ramping, and Reserves Analysis* by Anthony Giacomoni at December 14th, 2016 MC meeting.

Capacity markets are an important component of the long-run economic signals that support efficient investment and retirement decisions. However, the capacity market is designed to procure the amount of installed capacity necessary to satisfy system needs during the summer peak. The capacity market generally increases the resources available during the winter, but it does not explicitly consider system needs or risks that tend to escalate in the winter season, such as potential gas supply disruptions.

In this subsection, we evaluate how the available resource margins are expected to change during a winter cold spell in the coming years, accounting for expected changes in the resource mix. We then discuss the adequacy of ISO-NE's market rules for satisfying winter reliability needs.

Impact of Trends in Resource Mix on Winter Reliability

As New England and other regions become increasingly reliant on natural gas, the reliability councils have become more concerned with the effects of fuel supply disruptions on the bulk power system reliability. However, the criteria for ensuring reliability during fuel supply disruptions are still evolving. Lacking an established set of methods for evaluating fuel security during winter conditions, we analyze the potential for a fuel supply shortage over a two-week period of severe winter weather. Specifically, the following analysis compares electric generators' demand for oil and gas to the available supply in the region for four winter seasons: 2014/15, 2017/18, 2020/21, and 2023/24.

- The winter 2014/15 scenario shows actual conditions observed in the second half of February 2015, which is representative of prolonged severe weather conditions that can produce unique reliability needs the ISO may need to plan to satisfy.[32]
- Since the winter of 2014/15, 2.4 GW of non-gas resources have retired or have announced their retirement.[33]
- For the winter 2023/24 scenario, we assume that an additional 1.8 GW of non-gas resources (including the remaining coal-fired generation and roughly 1.3 GW of oil-fired capacity) will retire.[34] See Appendix for a list of underlying assumptions for Figure 7.

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32 January and February 2015 had the most HDDs of any two month period, with February being the colder of the two months. Electricity generation from oil and LNG based resources exceeded natural gas generation by 18 percent during the second half of February. See https://www.aga.org/knowledgecenter/facts-and-data/annual-statistics/weekly-and-monthly-statistics/heating-degree-day.

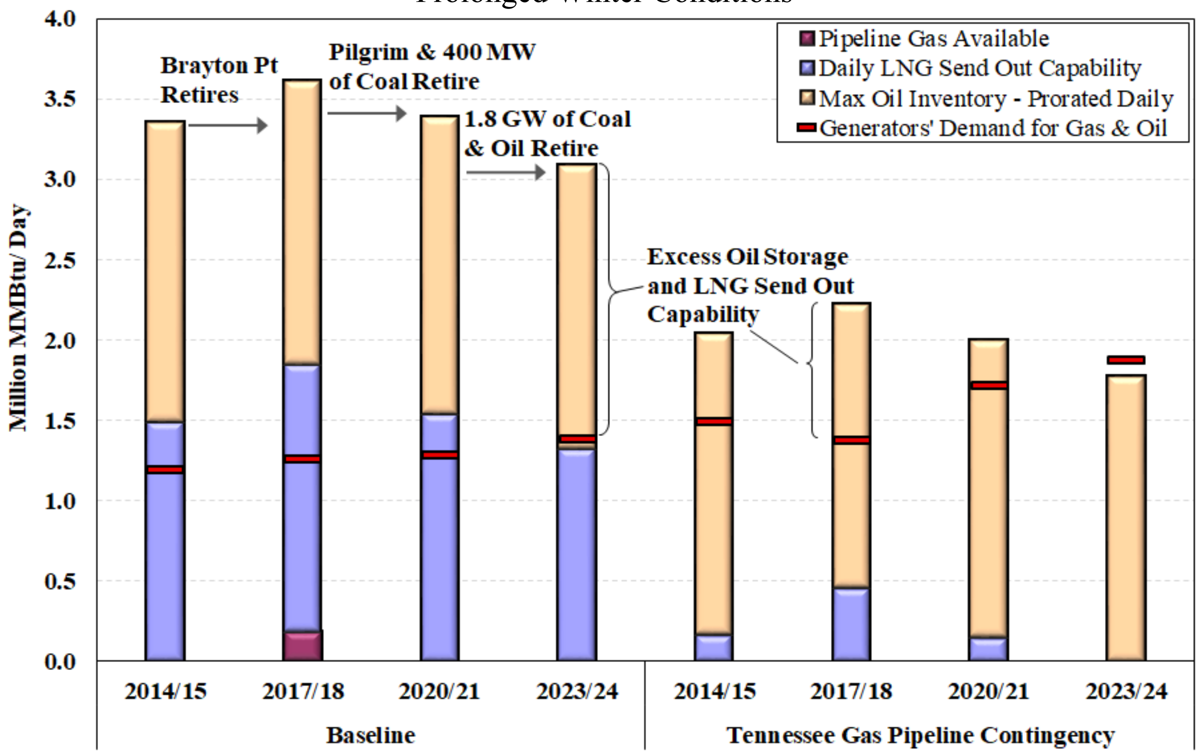
33 In addition, the owners of the coal-fired Bridgeport Harbor 3 ("BH-3") unit have agreed to retire the unit no later than July 1, 2021. See the February 25, 2016 "Community Environmental Benefit Agreement" between PSEG and the City of Bridgeport, available at http://www.ct.gov/csc/lib/csc/pending_petitions/2_petitions_1201through1300/pe1218/filing/pe1218_exhibitg.pdf.

34 The 1.8 GW of retirements corresponds to capacity in excess of the ICR in FCA-11 (adjusted for changes in load). This included 1.3 GW of oil-fired steam turbines that submitted delist bids in FCA-11.

For a period of two weeks of severe winter weather in each year, the following chart shows the total oil and gas supply available for generation. This supply includes LNG send out capability and prorated oil storage capacity, which is the available inventory assuming the oil storage facilities are completely utilized. The supply shown includes any available pipeline gas, but this was fully utilized by core gas demand under all but one of the scenarios studied.

This supply shown in the stacked bars is compared to the generators' daily average oil and gas demand (indicated by the red lines).[35] The amount by which the supply exceeds the demand represents the excess capacity. To evaluate the vulnerability of the system to fuel supply disruptions, the figure also shows an additional scenario where the amount of gas available is reduced as a result of a major outage on the Tennessee pipeline.[36]

Figure 7: Daily Potential Supply and Demand for Gas and Oil During
Prolonged Winter Conditions[37]



35 We include the capacities of Canaport, Distrigas and Exelerate facilities in the available LNG capability, so gas from Maritimes & Northeast pipeline is not included in the total pipeline gas available.

36 Pipeline contingency scenario assumes a loss of 1.32 Bcf/day in 2014/15 and 1.39 Bcf/day in the future.

37 Between Feb. 15-28, 2015, the total LNG send out exceeded the pipeline gas used by electric generators in New England. Accordingly, we reduced the total LNG capability by the difference between the two values.

The excess supply margin between the demand and potential supply of gas and oil is falling as the non-gas generators continue to retire and the core demand for natural gas grows. Hence, the share of total oil inventory and LNG capability needed to satisfy generators' demand is rising:

- From 35 percent in 2014/15 to 45 percent in 2023/24 in our Baseline scenarios, and
- From 73 percent in 2014/15 to 105 percent in 2023/24 in our Pipeline Contingency scenarios.[38]

In the Pipeline Contingency scenarios, the LNG capability drops substantially because the LNG send-out capacity is assumed to be consumed by core demand, which generally has first call on the pipeline capacity that would be used to deliver the LNG.

Although very little pipeline gas is likely to be available for electric generation after core demand is served, the aggregate LNG capacity and oil fuel inventory are theoretically sufficient to satisfy the generators' demand over a two week period of severe winter weather in the scenarios shown above. However, this conclusion is based on an assumption that the LNG supply and oil inventories are fully utilized, which may not be the case because:

- Significant economic and physical constraints that may limit the availability of LNG below the daily capacities of the LNG terminals. In recent winters, total LNG send out has been far below the maximum capacity.[39]
- Limits on the individual unit tank sizes and run hours can reduce the total useable oil inventory. For instance, an oil tank will be unavailable to the market if the generator it supplies experiences a forced outage.
- Since the oil inventory shown corresponds to all tanks being full, the actually available inventory will reflect the portion of the tanks that suppliers find it economic to fill.

In the Baseline scenarios shown in Figure 7, LNG capacity would become pivotal for meeting generators' demand in 2023/24, even if the oil storage is fully utilized. Unfortunately, the ownership of facilities necessary to import LNG is relatively concentrated. This raises competitive concerns regarding the vulnerability of New England to the exercise of market power in the fuel markets. Such concerns are difficult or impossible for the ISO to address through modifications to its tariff. Competitive concerns become more pronounced in the Pipeline Contingency scenarios shown in Figure 7 where LNG capacity is always pivotal for satisfying the generators' fuel demands.

Overall, this analysis reveals the essential role that both oil inventories and LNG play in ensuring fuel adequacy in winter. Any major reduction in the availability of either LNG or oil inventories could result in energy shortages in 2024. Unlike natural gas, the supply of these two fuels needs

38 Our results indicate that the demand for oil and gas in 2023/24 would exceed the available supply under the gas pipeline contingency scenario.

39 LNG deliveries must be arranged in advance. Physical delivery limitations and competing demands for LNG are constraints that can limit the available LNG once the severe winter conditions arrive.

to be secured days to months in advance to ensure timely availability. This highlights the importance of advance planning and efficient incentives to ensure fuel adequacy during winter months. In particular, it will be increasingly important for ISO-NE to consider how to ensure reliability as the winter fuel supply margin tightens in the coming years. The following part of this section discusses measures that could help ensure fuel security.

Issues with Existing Mechanisms for Addressing Winter Reliability Concerns

The previous analysis shows that the winter fuel supply margin are likely to tighten considerably in the coming years. In the Baseline cold weather scenario shown for 2023/24, 44 percent of potential oil inventory and LNG capacity would be required to satisfy electricity demand, but such high utilization rates may require some form of coordination to ensure fuel security.

The ISO's WRP has enhanced fuel security in recent winters by arranging for oil-fired, LNG-fired, and DR resources to procure the necessary fuel or be otherwise available during a ten-day cold spell.[40] Thus, the WRP has helped the ISO fulfill two key objectives:

- Providing a financial incentive for generators to take the necessary steps to import fuel before the winter.
- Supports the ISO's seasonal reliability planning function by ensuring sufficient fuel will be available and by providing the ISO fuel procurement commitments from the generators.

However, a significant drawback to the WRP has been that it is not technology neutral, compensating only certain types of resources. For example, a nuclear unit is not compensated in a comparable manner even though it may be able to provide comparable fuel security as an oil-fired unit. This preference for specific fuel types distorts incentives for investment in other technologies that can satisfy ISO-NE's reliability needs.

The WRP is scheduled to end by June 2018 when the PFP program will become effective. The ISO designed the PFP program as a means to provide resources with strong incentives to perform during periods of shortage. While PFP will provide substantial incentives for generators to procure the fuel needed to produce during shortage conditions, prolonged periods of severe weather could result in fuel shortages that are extreme as inventories are depleted. For example, ISO-NE has a large amount of fast start capacity with significant energy limitations (i.e., limitations on the number of hours the unit could operate before running out fuel). Although these conditions would produce severe financial consequences for the affected generators, it would also likely cause the ISO to fail to satisfy its Loss of Load Expectation requirements.

Hence, while PFP has the virtue of being technology neutral and will provide strong incentives for generators to procure the fuel that each believes is necessary to operate under severe winter

40 See Appendix K of Market Rule 1 of the ISO Tariff.

conditions, it will not provide the planning and coordination that may be necessary to ensure that ISO-NE's seasonal fuel security needs are satisfied. Such coordination is important because suppliers need to make commitments in advance to obtain specified quantities of fuel. It may be difficult for New England to achieve the high utilization rates of its oil storage capabilities and LNG capacity indicated by Figure 7 without some form of seasonal coordination.

D. Effects of State-Sponsored Procurement on Market-Based Investment Incentives

Several New England states have undertaken initiatives to encourage specific types of resources that satisfy environmental and other objectives but that would not otherwise be built based on market incentives. However, such state policies may distort capacity market outcomes and, thus, conflict with the objective of providing efficient economic incentives for investment and retirement. In this subsection, we discuss the scope of these challenges and the shortcomings of the current approaches in addressing these issues.

Table 1 summarizes the currently known state initiatives for supporting specific generation or transmission resources. For each initiative, we identified the magnitude of the potential entry in *capacity* terms (which are generally much lower than "nameplate" quantities). For example, on-shore wind is able to sell capacity equal to only 12 percent of its nameplate rating. In addition to the entry of renewables in Table 1, state entities are considering subsidies for nuclear resources (although these are projected to be economic under expected market conditions).[41]

Table 1: Potential Subsidized Entry Through 2026[42]

Auction *Delivery Yr*	FCA-12 *2021/22*	FCA-13 *2022/23*	FCA-14 *2023/24*	FCA-15 *2024/25*	FCA-16 *2025/26*	Total
Multi-State Clean Energy Solicitation	75	75				150
CT 2-20 MW Clean Energy Solicitation	38	38				75
Renewables required to meet RPS	66	66	66	66	66	332
MA Offshore Wind Solicitations					140	140
MA Clean Energy Solicitation		1200				1200
Total Entry Through FCA-16	**179**	**1379**	**66**	**66**	**206**	**1897**
Average Annual Entry						**379**

Subsidized entry and uneconomic retention distort the wholesale market prices when they lead to supply and demand disequilibrium (i.e., an artificial surplus). Such artificial surpluses undermine the ability of the market to facilitate efficient long-term decisions by market participants who rely on wholesale market revenues when deciding whether to invest in new generation, make capital improvements to existing units, or build new transmission facilities.

41 See https://www.cga.ct.gov/2016/lcoamd/2016LCO05586-R00-AMD.htm

42 See Subsection F of the Appendix for a list of underlying assumptions.

If state policies are achieved outside of the RTO markets and no attempt is made to moderate their effects on the market, the market will be less effective in facilitating resource adequacy and other benefits of competition. This would adversely affect suppliers in the market, leading states and consumers to bear much higher costs over the long run.

Issues with Existing Mechanisms for Accommodating State Intervention

ISO-NE has New Resource Offer Floor rules that are a form of minimum offer price rule ("MOPR"). These rules were designed to deter uneconomic entry by conventional generation that is built to suppress capacity prices below competitive levels, since such entry would otherwise undermine the market's ability to sustain the resource base needed to maintain reliability over the long-term. Since the MOPR prevents uneconomic entrants from causing prices to fall below competitive levels, it removes the impetus for a state to subsidize conventional generation. However, when public policy initiatives are not deterred by the MOPR and the resources enter, the MOPR produces unintended adverse consequences.

The Commission has recognized that renewable energy resources may be subsidized to meet public policy objectives and granted limited exemptions from the MOPR for renewable energy resources (e.g., 200 MW annually in New England). This annual limit is used to ensure that the quantity of renewables is not too large to be absorbed into the market without causing substantial artificial capacity surpluses and associated price distortions. However, some states are intending to subsidize larger quantities of generation for public policy reasons. ISO New England's MOPR provisions will not prevent the adverse market impacts of these state initiatives, so it is important to consider alternative provisions for addressing these issues.

Any mechanism developed to accommodate legitimate state policies should be evaluated based on the extent to which the mechanism:

- Protects the credibility of the market by minimizing artificial surpluses
- Prevents the inefficient entry of new conventional resources, given the entry of the subsidized resources (i.e., preventing investment in unnecessary resources), and
- Minimizes excess costs to be borne by the RTOs' customers.

A traditional MOPR is very effective at deterring subsidized entry that is intended to lower capacity prices, but it generally performs very poorly against these objectives when applied to public policy resources that are not deterred. Therefore, we developed an alternative to the existing MOPR in collaboration with ISO-NE. We discuss the alternative and proposed enhancements in Subsection G.

E. Costs of Strategies for Satisfying Reliability and Environmental Objectives

Public policy objectives are generally most economic when the objective is priced in the market in a technology-neutral manner. Out-of-market initiatives that provide undue preference for certain technologies or individual resources will generally increase costs. To illustrate this point, we evaluate economics of several generic approaches to reduce carbon emissions and/or to reduce dependence on natural gas-fired resources during peak winter conditions (although we recognize that the costs of individual projects vary based on particular circumstances). Based on estimated net revenues in 2020/21, we estimate the costs of reducing CO_2 emissions through investment in different types of renewable resources or by retaining existing nuclear resources. These results are summarized in Table 2. These strategies may also address other objectives, such as improving winter reliability by reducing the system's reliance on gas and improving the system's ability to integrate intermittent resources. Therefore, we qualitatively indicate the effectiveness of these strategies in achieving these other objectives in the right panel of the table.

Table 2: Strategies for Reducing Carbon Emissions and Enhancing Winter Reliability

Strategy	$/ton of CO2 reduced	Reduces Carbon Emissions	Promotes Winter Reliability	Helps Integrate Renewables
Build New Offshore Wind	$218	✓✓	✓	✗
Import Hydropower from HQ	$37 to $98	✓✓✓	✓✓✓	✓✓
Retain Existing Nuclear Plants	$0	✓✓✓	✓✓✓	
Build New Onshore Wind	$67 to $119	✓✓	✓	✗
Build New Solar PV	$111	✓✓		✗
Build New Dual-Fuel CC	$36 to $56	✓	✓✓✓	✓✓✓

As shown in Table 2, these alternative strategies vary substantially in cost and effectiveness for addressing concerns related to carbon emissions, renewable integration, and winter fuel security. For example:

- Because we estimate that nuclear resources are likely close to covering their going forward costs in the ISO-NE markets, retaining them is the lowest cost means to reduce CO_2 emissions (or prevent them from rising);[43]
- New combined cycle units would also reduce carbon emissions at a higher cost (which is highly dependent on the type of resource it would displace), but their flexibility would provide sizable benefits for enabling the integration of larger amounts of intermittent renewable resources.[44]
- Building offshore wind units would enhance winter reliability by reducing the need for gas and oil generation. However, building new or retaining existing dual-fuel generation provides greater reliability value due to the intermittent nature of offshore wind.[45]

43 This assumes that a retiring nuclear unit would lead to increased generation with an average carbon intensity 0.45 tons per MWh.

44 The range for the cost of reducing carbon for combined cycle is based on the net revenues for units with access to gas priced at: Algonquin city gates and Iroquois Zone 2. We assume that the combined cycle would displace generation with an average carbon intensity of 0.65 tons/MWh. The cost of reducing carbon using a combined cycle varies based on revenues at different locations and the efficiency of the unit.

45 The range for cost of reducing carbon using onshore wind units is based on the net revenues for units located at two different locations – Maine and internal hub. This assumes that the new renewable units

- Importing hydropower from Canada would reduce carbon emissions and promote winter reliability, but if it operates with a high capacity factor, it will not be as effective as a combined cycle unit at integrating intermittent renewable generation.[46]

Investment in a particular technology tends to crowd-out investment in the alternatives, so it is important to consider how each of the strategies listed would affect other technologies in New England. As illustrated above, there is large disparity in the economics and the type of impacts of each of the strategies listed. None of the strategies we analyzed offer a complete solution to the complex and interrelated challenges facing the region's electric system.

This underscores the value that markets provide in coordinating the decisions of market participants to achieve various economic, reliability and other policy objectives. By pricing these objectives, the markets will provide powerful incentives that are aligned with the objectives. Designating a preference for one technology or strategy to the exclusion of others will not be as effective in achieving the public policy objectives, while undermining the market's ability satisfy the region's fundamental reliability and cost objectives. Therefore, we continue to encourage the states and ISO to pursue technology-neutral, market-based approaches to achieve public policy objectives. Given that a number of technology-specific initiatives are underway by some of the states in New England, we have been working with ISO-NE to develop an approach that would minimize the market harm of these actions. This recommended approach is described below.

F. Improving the Competitiveness of the FCA

In our 2015 State of the Market Report, we evaluated the supply and demand in the FCA and concluded that:[47]

- Limited competition can enable a single supplier to unilaterally raise the capacity clearing price by a substantial amount.
- Publishing information on qualified capacity (new and existing) ensures that suppliers will recognize when they can benefit by raising capacity prices.
- To the extent that the qualification process limits the number of new resources participating in the auction, the competitiveness of the auction will be reduced.

would displace generation with an average carbon intensity of 0.45 tons per MWh. Note that our analysis does not include interconnection costs, integration costs at high penetration levels of renewables could increase the cost of reducing carbon emissions by wind generation.

46 The range for cost of reducing carbon using hydropower imports is based on capital costs which are dependent on the extent to which the transmission line is buried. This assumes that the imported hydropower via HVDC lines would displace generation with an average carbon intensity of 0.45 tons per MWh.

47 See *2015 Assessment of the ISO New England Electricity Markets*, Potomac Economics. Available at: https://www.iso-ne.com/static-assets/documents/2016/06/isone_2015_emm_report_final_6_14_16.pdf

To address these concerns, we identified market changes that could enhance competition in the FCA, including:

- Reducing any unnecessary barriers to participation, which helps provide additional competitive discipline that reduces the incentive for a supplier to raise its offer substantially above its net CONE.
- Reducing the amount of information available on new and existing resources before the auction to make it more difficult for a pivotal supplier to determine its profit-maximizing offer and encourage new suppliers to offer competitively at prices closer to their net CONE.[48]

Additionally, we have raised competitive concerns regarding the descending clock auction format. The descending clock auction format is sometimes touted over sealed bid formats because it provides auction participants with information about the value of a good.[49] However, in the FCA, sellers generally do not receive information that is useful in establishing a competitive offer. Instead, the information learned through the auction process is primarily useful in determining when to leave the auction in order to set the highest price and receive the highest capacity revenue possible. In particular, the ISO-NE clock auction provides the amount of excess supply at the system-level and at each interface at the end of each auction round. Hence, suppliers may know when they are pivotal market-wide and, if the new resources are concentrated at a particular zone or interface, this information will allow suppliers to infer how supply conditions may be changing at that location. Hence, we continue to recommend the ISO consider transitioning to a sealed bid auction format, which would address the competitive concerns associated with the descending clock auction format.

G. Conclusions and Recommendations

ISO-NE's capacity market was designed around the objective of maintaining resource adequacy by attracting investment in installed capacity to satisfy summer peak conditions. While it has been successful in meeting this objective, three concerns have arisen in recent years that may need to be addressed with changes in the ISO-NE capacity market.

Addressing Winter Fuel Security Concerns

First, New England has become increasingly reliant on natural gas and vulnerable to disruptions in fuel supplies to the region. Over the decade from 2010/11 to 2020/21, about 4 GW of nuclear, oil and coal-fired capacity has retired or will retire, while the remaining oil and coal-fired

48 The 2015 Annual Report identifies six types of information in addition to the Interconnection Queue that is published by the ISO that should be reviewed and modified as appropriate.

49 In most cases, this type of auction is employed on the demand side with buyers determining when to stop the clock and set the price.

capacity in New England will be economically challenged by falling capacity prices, the phase-in of PFP, and the entry of state-subsidized resources.

Although it appears that the oil inventory capacity and LNG import capability to New England are high enough to satisfy the demand for these fuels during a severe winter event, it would require very high utilization rates—far above any that have been observed in the past. Our fuel security assessment for a two-week severe winter period showed that while the system required 35 percent of this capability in the winter 2014/15, it is projected to require:

- 45 percent in 2023/24 in our baseline scenario, and
- 105 percent in 2023/24 in a severe pipeline contingency scenario.

These trends raise questions about whether the current planning processes and market requirements are adequate to ensure fuel security by motivating generators to procure adequate fuel. Undoubtedly, ISO-NE's shortage pricing and PFP framework provides very strong incentives for suppliers to be available during such conditions. However, these conditions may be difficult to predict and may need to be explicitly recognized in the ISO's planning processes to satisfy its one-in-ten reliability standard.

The ISO's WRP has enhanced fuel security in recent winters by arranging for oil-fired, LNG-fired, and DR resources to procure the necessary fuel or be otherwise available during a ten-day cold spell. Thus, the WRP supported the ISO's seasonal reliability planning function by providing the ISO fuel procurement commitments from the generators. However, it did not create efficient incentives for other technologies that can satisfy ISO-NE's winter reliability needs. The WRP is scheduled to end by June 2018 when the PFP program becomes effective.

Hence, while PFP has the virtue of being technology neutral and will provide strong incentives for generators to procure the fuel that each believes is necessary to operate under severe winter conditions, it will not provide the planning and coordination that may be necessary to ensure that ISO-NE's seasonal fuel security needs are satisfied. Thus, ISO should evaluate whether it has planning needs for the winter that must be met to satisfy its overall reliability criteria. If so, we recommend that the ISO evaluate: a) the adequacy of the PFP framework in satisfying these needs, and b) the potential benefits and costs of market design changes that would complement PFP and facilitate the advance procurement of the fuel to needed ensure fuel security.

Alternative Mechanisms to Accommodate State-Sponsored Resources

States are promoting certain public policies by subsidizing investment in individual generating facilities, which threatens to undermine the incentives for market-based investment. In our review of state initiatives to encourage development of renewable generation, we find that generation with a capacity value of 1.9 GW is expected to enter in the next five FCAs. Given the current capacity surplus and the lack of growth in electricity demand, this disrupts the market by artificially depressing capacity and energy prices. This disruption will affect not only the markets and participants currently, but will raise costs for the New England region by adversely affecting participants' investment and retirement decisions for years to come.

Many of the New England state public policy initiatives have been justified as helping to reduce CO_2 and other emissions. Employing market-based solutions to price emissions can achieve emission reductions at a lower cost than subsidies for specific classes of generation. In that regard, the Regional Greenhouse Gas Initiative ("RGGI") is a successful cap-and-trade market operating in the region that could be modified to address many of the states' goals. However, the New England states have expressed several concerns with relying on the RGGI market or any form of carbon pricing.[50] As a result, beginning in late 2016 we collaborated with ISO-NE to develop a mechanism for accommodating legitimate public policy investment while maintaining a well-functioning wholesale market that can still attract market-based investment.

The result of this collaboration is the Competitive Auctions with Subsidized Policy Resources ("CASPR"). This proposal recognizes the key issue – that the disruptive effects of out-of-market subsidies result from the artificial short-term supply surpluses they create, which distort capacity and energy prices. Hence, CASPR would coordinate the entry of subsidized resources with retirements of existing resources to ensure that subsidized entry does not lead to artificial capacity surpluses. Under CASPR, the FCA would be conducted in two passes of the auction:

- Initial FCA auction: Includes all of the subsidized resources subject to a minimum offer price per the current rules, with other existing and new resources clearing as normal.
- Substitution auction: Allows the subsidized resources that did not clear in the first pass to purchase the initial capacity obligation from an existing resource submitting a retirement delist bid or a new conventional resource clearing in the initial FCA auction.

Conventional new and retiring resources would be eligible for substitution because they would modify the long-term supply balance to offset the subsidized entry. Including new conventional resources that cleared in the initial FCA is particularly important to ensure that the FCA does not facilitate inefficient investment.

Although there are other important details to this proposal, we believe this general approach strikes a reasonable balance between accommodating legitimate public policy initiatives, while protecting the performance and viability of the RTO's wholesale electricity markets. We recommend the ISO examine the following issues as it moves forward with this proposal:

- The development of a settlement rule for conventional new resources in the substitution auction to provide efficient incentives and avoid potential manipulation concerns.
- The ISO should consider whether to allow the retirement offers to be updated after the initial FCA is conducted, which will likely result in more efficient and competitive offers.

50 See NESCOE's April 7th, 2017 memo on *Feedback to NEPOOL on Long-Term "Achieve"-style IMAPP proposals*, available at http://nepool.com/uploads/IMAPP_20170517_NESCOE_Memo_20170407.pdf.

Although there are other important details to this proposal, we believe this general approach strikes a reasonable balance between accommodating legitimate public policy initiatives, while protecting the performance and viability of the RTO's wholesale electricity markets. We recommend the ISO examine the following issues as it moves forward with this proposal:

- It is important that the FCM not facilitate inefficient investment in new resources, given the entry of the subsidized resources. Hence, it will be important for conventional new resources clearing in the first pass to be candidates for substitution in the second pass of the CASPR, rather than limiting the substitution to retiring units.
- The results of the first pass could influence the efficient second pass offer for a retiring unit. Therefore, ISO should consider whether to allow the retirement offers to be updated after the first pass or to be contingent on the first pass outcomes.

Adjusting the MOPR to Reflect the Pay-For-Performance Framework

Under the pay for performance rules, most of the value of capacity in the long-run will be embedded in the performance payments. Participants that sell capacity are essential engaging in a forward sale of the expected performance payments (they receive the capacity payment up front in exchange for not receiving the performance later when they are running during a shortage). However, resources that do not sell capacity can earn comparable revenues by simply running during shortages and receiving the performance payments. In other words, a supplier has two options:

- Sell capacity and commit to producing energy during shortages. Hence, the supplier relinquishes the performance payments in could have earned and will be charged the performance rate as a penalty; or
- Do not sell capacity and earn the performance payment by producing during the shortages.

In equilibrium, these two options should produce the same expected revenues. MOPR precludes an uneconomic entrant from selling capacity (choosing the first option), which simply means that the mitigated resource would default to option 2. Because option 2 should provide substantial expected revenues, the MOPR will not likely be an effective deterrent under the PFP framework.

Further the uneconomic entrant will be able to depress capacity prices without selling capacity because it will lower the expected number of shortage hours. A rational offer for capacity under PFP will include the foregone performance payments. Because the uneconomic entrant will reduced the expected frequency of shortages, it should reduce the offer prices from the capacity suppliers in the region and lower capacity prices. Therefore, we would recommend the ISO making uneconomic units that were mitigated under the MOPR ineligible to receive performance payments. This recommendation may be needed to facilitate the effectiveness of the CASPR proposal discussed above.

III. Causes and Allocation of NCPC Charges

When resources are scheduled at clearing prices that are not sufficient for them to recover their full as-bid costs, the revenue shortfall is covered with an NCPC payment. Although the overall size of NCPC payments are small relative to the overall New England wholesale market, NCPC payments are important because they usually occur when market clearing prices are not fully efficient and because they can distort the incentives of individual market participants. Thus, we evaluate the causes of NCPC payments in order to identify potential market inefficiencies.

NCPC payments can undermine the incentives for suppliers to offer competitively. Wholesale electricity markets like ISO-NE's market use a uniform price auction because it helps coordinate the scheduling decisions of many sellers. The profit-maximizing offer of a competitive supplier in a uniform price auction is its short-run marginal cost, which it can determine without having to make predictions of market clearing prices. The ISO can optimize its commitment and dispatch based on such offers to minimize the costs of satisfying system demand and reserve requirements. In some cases, however, NCPC payments provide incentives for suppliers to raise their offer prices to increase their payments. Suppliers that frequently receive NCPC payments may have incentives to deliberately increase their costs by procuring more expensive fuel.

Most NCPC payments occur when an operating requirement is not fully reflected in the market's requirements and must therefore be satisfied by scheduling a generator outside of the market. The cost of this action will be reflected in NCPC payments rather than in market-clearing prices. Ultimately, this undermines the economic signals that govern behavior in the day-ahead market in the short-term and investment and retirement decisions in the long-term.

Additionally, intermittent renewable generation will likely become more prevalent over the coming decade, which will increase the value of flexible resources. NCPC payments do not provide efficient incentives because they generally reward resources for being high-cost and inflexible. Hence, NCPC payments tend to shift investment incentives away from flexible resources at locations that bolster transmission security and reliability.

This section evaluates the causes of NCPC charges in 2016 and discusses implications for market efficiency, divided into subsections that address the following topics:

- Comparison of uplift charges and allocations in ISO-NE versus other markets;
- Primary drivers of day-ahead NCPC charges;
- Local second contingency protection requirements that lead to day-ahead NCPC charges;
- System-level operating reserve requirements that lead to day-ahead NCPC charges;
- Discussion of significant drivers of real-time NCPC charges; and
- Summary of conclusions and recommendations.

A. Cross-Market Comparison of Uplift Charges and Cost Allocation

Before discussing the causes and implications of various classes of NCPC costs (generally referred to as "uplift" costs industry-wide), it is useful to place ISO-NE's NCPC charges in context. Table 3 shows its total day-ahead and real-time NCPC charges over the past two years, and the comparable 2016 uplift charges for the NYISO and the MISO. Because the size of the ISOs varies substantially, the table also shows these costs per MWh of load. Recognizing that some RTOs differ in the extent to which they make reliability commitments in the day-ahead horizon versus real-time, the table includes a sum of all day-ahead and real-time uplift at the bottom to facilitate cross-market comparisons.

Table 3: Summary of Uplift by RTO
2015 & 2016

		ISO-NE		NYISO	MISO
		2015	**2016**	**2016**	**2016**
Real-Time Uplift					
Total	**Local Reliability ($M)**	$25	$1	$10	$3
	Market-Wide ($M)	$58	$27	$14	$107
Per MWh of Load	**Local Reliability ($/MWh)**	$0.19	$0.01	$0.06	$0.00
	Market-Wide ($/MWh)	$0.45	$0.22	$0.09	$0.16
Day-Ahead Uplift					
Total	**Local Reliability ($M)**	$24	$31	$16	$22
	Market-Wide ($M)	$12	$13	$2	$19
Per MWh of Load	**Local Reliability ($/MWh)**	$0.18	$0.25	$0.10	$0.03
	Market-Wide ($/MWh)	$0.10	$0.10	$0.01	$0.03
Total Uplift					
Total	**Local Reliability ($M)**	$48	$33	$27	$25
	Market-Wide ($M)	$70	$40	$16	$125
Per MWh of Load	**Local Reliability ($/MWh)**	**$0.38**	**$0.26**	**$0.17**	**$0.04**
	Market-Wide ($/MWh)	**$0.55**	**$0.32**	**$0.10**	**$0.19**
	All Uplift ($/MWh)	**$0.92**	**$0.58**	**$0.27**	**$0.22**

The table shows that ISO-NE made substantial progress in reducing its NCPC from 2015 to 2016 by eliminating a flaw in its NCPC payment rules in early 2016, which had previously allowed resources whose costs were fully covered in the day-ahead market to receive additional real-time NCPC payments. However, the table shows that ISO-NE still incurs substantially more uplift costs, adjusted for its size, than other RTOs. Its total NCPC costs per MWh was roughly double the costs incurred by NYISO or MISO in 2016. This difference can be attributed to the following factors, some of which are already being addressed by reforms ISO-NE implemented in early 2017:

- ISO-NE's fuel costs tend to be higher than the other RTO's, leading to higher required make-whole payments.

- Both NYISO and MISO allow fast start units to set prices that may otherwise require uplift payments to cover their as-bid costs. ISO-NE implemented a similar approach in 2017 that is expected to lower NCPC uplift costs significantly.
- ISO-NE and NYISO incur larger amounts of uplift to satisfy local second contingency protection requirements, which are much less prevalent in the MISO footprint.
- ISO-NE and MISO both settled on hourly prices and production (rather than settling at the interval level). This leads to higher real-time uplift charges to compensate resources that incur losses as a result of being flexible. ISO-NE implemented sub-hourly pricing in early 2017, which should reduce this category of uplift.

ISO-NE allocated the vast majority of real-time NCPC charges to real-time deviations, including virtual transactions. In organized wholesale power markets, virtual trading plays a key role in the day-ahead market by providing liquidity and improving price convergence between day-ahead and real-time markets. However, we have observed relatively low levels of virtual trading in the ISO-NE compared to other markets we monitor, which we attribute primarily to the large allocation of NCPC charges (per MWh) to virtual transactions and virtual load in particular.

Table 4 shows the average volume of virtual supply and demand that cleared the three eastern RTOs we monitor as a percent of total load, as well as the gross profitability of virtual purchases and sales. Gross profitability is the difference between the day-ahead and real-time energy prices used to settle the energy that was bought or sold by the virtual trader. The gross profitability does not account for uplift costs allocated to virtual transactions, which are shown separately.

Table 4: Virtual Transaction Volumes and Profitability
2016

Market	Virtual Load		Virtual Supply		Uplift Charge Rate
	MW as a % of Load	Avg Profit	MW as a % of Load	Avg Profit	
ISO-NE	1.3%	$1.70	2.0%	$1.94	$1.25
NYISO	6.5%	$1.01	13.9%	$0.26	$0.10
MISO	8.6%	$0.29	9.5%	$0.95	$0.48

Although Table 4 shows that virtual trading generally improved price convergence between the day-ahead and real-time markets in in 2016 because it was profitable, the virtual trading levels were a fraction of the levels (less than 20 percent overall) observed in NYISO and MISO.

Most of the differences shown in the table between ISO-NE and the other RTOs can be attributed to ISO-NE's NCPC allocation methodology, which raises significant concerns. The high and uncertain NCPC charges provide a substantial disincentive for firms to engage in virtual trading because virtual profits tend to be small relative to day-ahead and real-time prices. This reduces liquidity in the day-ahead market and explains why the gross profitability of virtual transactions is larger in ISO-NE than the other RTOs (i.e., the day-ahead and real-time prices are not as well arbitraged). Hence, we continue to recommend the ISO modify the allocation of Economic NCPC charges to be more consistent with a "cost causation" principle, which would involve not allocating NCPC costs to virtual load and other real-time deviations that cannot reasonably be argued to cause real-time economic NCPC. FERC has recently proposed similar uplift allocation changes in a notice of proposed rulemaking that would address this recommendation.[51]

B. Drivers of Day-Ahead NCPC Charges

Day-ahead NCPC charges are incurred when a resource is scheduled in the day-ahead market, but the revenues it receives from selling energy are not sufficient for it to recoup its as-offered start-up, no-load, and incremental costs. In addition to clearing day-ahead bids and offers in the day-ahead market, ISO-NE also commits resources in the day-ahead market to satisfy all of its forecasted reliability needs for the following day. Thus, most NCPC charges for reliability commitments are incurred in the day-ahead rather than the real-time market (as is the case for most other RTOs).

Satisfying reliability requirements in the day-ahead market is more efficient than waiting until after the day-ahead market clears because commitments that are made to satisfy a reliability requirement affect which resources should be committed economically in the day-ahead market. For example, if a 400 MW generator must be committed for reliability in a particular load pocket, the generator also helps satisfy demand throughout the system so it will likely reduce the amount of resources that are economic to commit outside the load pocket.

To summarize the causes of day-ahead NCPC, Figure 8 shows NCPC charges in 2016 incurred for the following reasons: local second contingency protection, voltage support, local single contingency protection, system-level reserve requirement, and other.[52] The figure also provides regional subtotals for local second contingency protection. The largest contributor to NCPC charges in the day-ahead market is commitments to satisfy local second contingency requirements, primarily in Boston. The next largest contributor is commitments to satisfy system-level ten-minute spinning reserve requirements. The market effects of these commitments are analyzed later in this section – local second contingency commitments are evaluated in Subsection C, and commitments for system-level ten-minute spinning reserves are evaluated in Subsection D.

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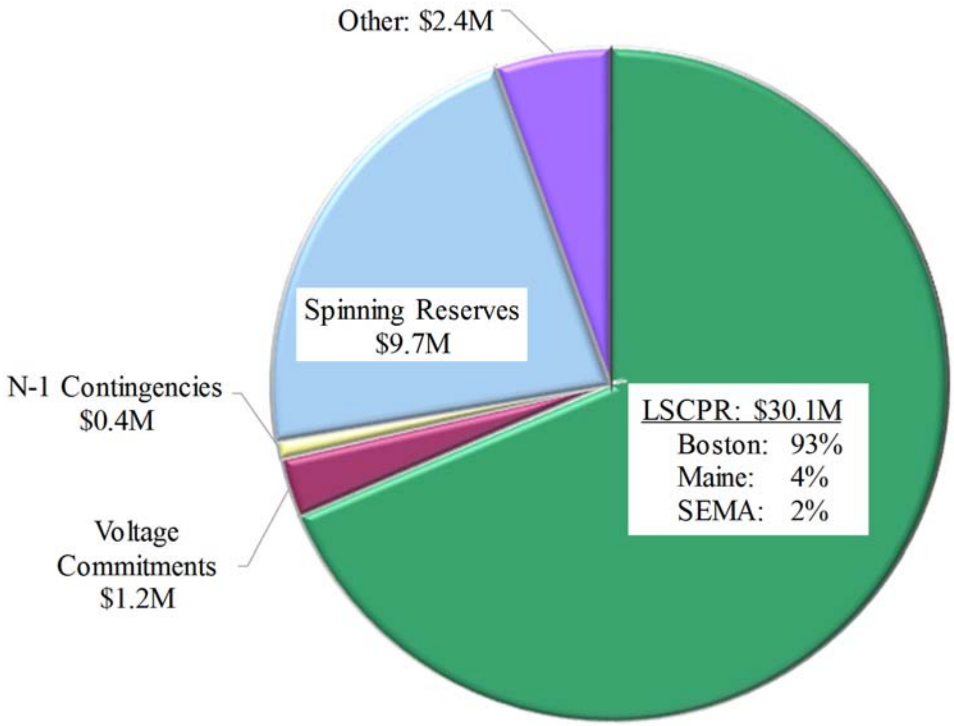
51 *Uplift Cost Allocation and Transparency in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Federal Energy Regulatory Commission, Docket No. RM17-2-000, January 19, 2017.

52 *Local second contingency protection resources* are committed to maintain sufficient reserves to protect an area in case the two largest contingencies were to occur in a 30-minute period. *Voltage support resources* are committed to maintain local voltage or resolve a reactive power requirement. *Local first contingency protection resources* are committed to maintain transmission security in case a contingency was to occur unexpectedly. *System-level reserve requirements* are defined for TMSR, TMNSR, and TMOR, and resources may be committed to satisfy those requirements in the day-ahead market.

Figure 8: Summary of Day-Ahead NCPC Charges by Category
2016



One notable factor that leads to inefficient commitments for local reliability, depressed clearing prices, and increased NCPC charges is that some combined-cycle generators are offered in a multi-turbine configuration even though they are able to operate the turbines individually. In many cases, the reliability requirement could be satisfied with the commitment of a single turbine configuration, so needlessly committing the multi-turbine configuration displaces other more efficient generating capacity. Multi-turbine combined-cycle commitments accounted for 42 percent of the capacity committed for local reliability in the day-ahead market in 2016. We evaluate the market effects of these excess commitments in 2016 in Subsection C.

C. Day-Ahead Commitment for Local Second Contingency Protection

The ISO commits resources for local second contingency protection needs in the day-ahead market. The purpose of these commitments is to ensure that ISO-NE can reposition the system in key areas to be able to respond to the second largest system contingency after the largest contingency has occurred.

While these commitments may be justified from a reliability perspective, they can lead to inefficient prices in the local area for two reasons.

- First, the units receiving NCPC payments systematically receive more revenue than the market revenues and cause lower-cost resources to set energy prices.

- Second, the costs of these resources will not be reflected in the prices of the operating reserves that are also satisfying the underlying reliability requirement.

These two issues distort economic incentives in favor of high-cost units with less flexible characteristics. Hence, when local NCPC is substantial, it is important to identify the underlying causes and consider market reforms as needed to improve the efficiency of prices for energy and operating reserves in local areas.

These concerns are sometimes exacerbated by two other issues that can lead to excess commitment for local second contingency protection.

- First, the day-ahead commitment software does not model the full set of energy and operating reserve requirements, particularly when the commitment of a large unit will alter one of the contingencies for which the software is scheduling. The ISO represents these factors indirectly in the day-ahead commitment logic, but this does not minimize costs because the procurement of operating reserves is not co-optimized with energy.
- Second, some generators that are committed for local second contingency protection offer as a multi-turbine group, requiring the ISO to commit multiple turbines when one turbine would be sufficient.

Of capacity that was committed by the day-ahead market model for local second contingency protection in Boston in 2016, we estimate that 75 percent of the capacity would not have been needed to satisfy the local second contingency requirements modeled in the day-ahead market if energy and operating reserves had been co-optimized with the requirement.[53]

The ISO could avoid excess commitment by: (a) implementing ancillary services markets that are co-optimized with energy in the day-ahead market, and (b) modifying its tariff to require capacity suppliers to offer multiple unit configurations to allow the ISO to commit just one turbine at a multi-turbine group. Not only would these changes result in production cost savings and more efficient prices for energy and reserves as discussed above, but they would also improve market incentives for reliable performance, flexibility, and availability under a wide range of conditions—not just operating reserves shortages. Directing more revenue to generators that have these characteristics would shift investment accordingly and reduce reliance on the capacity market for attracting investment to local areas.

Finally, satisfying these local requirements through a day-ahead operating reserve market and commitment should substantially reduce the need to commit resources out-of-market in the local

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53 Note, this evaluation considered only local second contingency protection commitments in Boston that were made by the day-ahead market's commitment software, but it does not include commitments that were determined by operations before the day-ahead market. When interpreting these results, it is also important to consider that local second contingency protection units might still have been committed for another constraint even if they were not needed specifically to satisfy the minimum capacity requirement for the local area.

areas that currently receive sizable NCPC payments. These NCPC payments provide adverse fuel procurement incentives. Under the market power mitigation rules, a generator that is committed for reliability can make more money by operating on a more expensive fuel because the relevant offer cap is calculated as a percentage over the generator's estimated cost.[54] For example, one dual-fuel generator in Boston operated on fuel oil for 69 days in 2016 when natural gas was less expensive than fuel oil.[55] Enforcing a requirement that generators committed for reliability burn the most economic fuel will reduce the frequency of commitments that require substantial NCPC payments. Ultimately, this will improve price signals for energy and reserves, and lower costs for the ISO's customers.

D. Day-Ahead Commitment for System Level Operating Reserve Requirements

As discussed in Subsection B, the day-ahead market software commits sufficient resources to satisfy system-level operating reserve requirements in addition to energy schedules. However, these reserve requirements are not enforced in the day-ahead market pricing software because ISO-NE does not have day-ahead reserve markets. Consequently, generators are frequently committed in the day-ahead market to satisfy operating reserve requirements, but the clearing prices of energy (and reserves) are understated because they do not reflect the costs of satisfying the reserve requirements. We estimate that:

- Additional generating capacity was committed to satisfy the system-level 10-minute spinning reserve requirement in approximately 4,300 hours in 2016.[56]
- Since the reserve requirement is not enforced in the pricing software, these commitments reduced energy prices across the system by an average of $1.30/MWh across all hours.
- Pricing these operating reserve requirements in the day-ahead market would provide efficient compensation for resources providing ten-minute spinning reserves.

Setting more efficient prices for energy and spinning reserves would provide better incentives for reliable performance, flexibility, and availability. This will become increasingly important as the penetration of intermittent renewable generation increases over the coming decade. Under-compensating generators that have flexible characteristics shifts investment incentives towards other types of resources and increases dependence on the capacity market for attracting the investment necessary to maintain reliability.

54 See Section III.A.5.5.6.2. of the ISO Tariff.

55 See EPA Air Markets Program Data at https://ampd.epa.gov/ampd/.

56 We found very few hours in 2016 when additional capacity was committed to satisfy the total 10-minute reserve and 30-minute reserve requirements. This is likely because New England has sufficient offline fast start capacity to satisfy these requirements in the vast majority of hours.

E. Drivers of Real-Time NCPC Charges

Real-time NCPC charges are incurred when a resource is scheduled in the real-time market, but the revenues it receives are not sufficient for it to recover its as-offered commitment and dispatch costs.[57] Table 5 summarizes real-time NCPC charges in 2016. In addition to the local reliability categories discussed earlier in this section, Table 5 shows real-time NCPC charges for the following categories:

- Real-Time Scheduling versus Pricing Inconsistencies:
  - Payments for Following Dispatch – Generators that lose profits by following dispatch instructions under the hourly settlement are held harmless (paid the lost profit).
  - Postured for Reserves – Generators that are held in reserve even when it would be more profitable to generate are paid their opportunity cost.
  - Economic Fast Start Units – These are fast start units that are dispatched in merit order by the real-time market, but that do not set price.
  - External Transactions – These are scheduled based on their offer price, but receive NCPC if the real-time price is below their offer.
  - Regulation Units – The regulation signal may lead them to generate at a loss because regulation deployments do not consider economic dispatch.
- NCPC Payment Flaw – The ISO corrected an NCPC flaw that led to unnecessary payments to resources scheduled day-ahead.[58] These payments ceased after January 2016.
- System Level Capacity Requirement – Ensures sufficient online and fast start capacity is available to satisfy the forecasted energy and operating reserve requirements.

While NCPC charges in the local reliability categories are allocated to specific load customers, the other categories in Table 5 are allocated to “real-time deviations.”[59]

The three of the four largest categories shown in Table 5 have been addressed by three significant market reforms that will reduce or eliminate the associated NCPC charges and improve the efficiency of real-time prices.

- Payments for Following Dispatch – At the end of February 2017, ISO-NE implemented real-time sub-hourly settlements so that generator settlements are based on prices and output in each interval, rather than averaged over the hour. This should substantially reduce the NCPC paid related to following dispatch.

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57 This includes opportunity costs if a generator would have earned more by not following the ISO’s instructions.

58 For a discussion of this issue, see Section II.B. of the *2015 Assessment of the ISO New England Electricity Markets*, Potomac Economics, June 2016.

59 Real-time deviations refer to the differences between day-ahead and real-time commitments of a resource.

- Economic Fast Start Units – At the end of February 2017, ISO-NE implemented real-time pricing software that allows fast-start peaking resources to set clearing prices, so payments to fast-start units should be reduced accordingly.
- NCPC Payment Flaw – At the end of January 2016, the ISO corrected this issue.

Table 5: Summary of Real-Time NCPC Charges by Category
2016

Real-Time NCPC Category:	Charges (in millions)	Share of RT
Local Reliability:		
Local Second Contingency	$0.8M	3%
Voltage Support	$0.2M	1%
SCR	$0.1M	0.3%
Multi-Turbine portion	$0.4M	1%
Real-Time Scheduling v Pricing:		
Following Dispatch	$8.6M	30%
Postured for Reserves	$5.4M	19%
Economic Fast Start Units	$4.1M	14%
External Transactions	$1.3M	5%
Regulating Units	$0.2M	1%
Real-Time Payment Flaw	$4.9M	17%
System Level Capacity	$2.6M	9%

Local reliability requirements account for a small share (5 percent) of real-time NCPC because these requirements are ordinarily satisfied in the day-ahead market. The system level capacity requirement also accounted for a small share (9 percent) of real-time NCPC charges even though this requirement is not specifically enforced in the day-ahead commitment software. This is likely because the day-ahead commitment for local reliability and system-level operating reserve requirements also contribute to satisfying the system level capacity requirement.

It is important to allocate NCPC charges in an efficient manner. However, most of the NCPC charges that are allocated to real-time deviations are not caused by real-time deviations. Specifically, we find that the non-local reliability categories (which accounted for 95 percent of real-time NCPC charges) are mainly driven by factors other than real-time deviations.

The system level capacity requirement is the only category that is driven partly by real-time deviations and this accounted for just 9 percent of real-time NCPC charges. These commitments are sometimes caused by under-scheduling of energy in the day-ahead market or the loss of a significant supply resource after the day-ahead market. So, real-time deviations that reduce scheduling of physical resources in the day-ahead contribute to this category of NCPC charges, which includes virtual supply, under-scheduled load, or a generator that experiences a forced outage after the day-ahead market.

This misallocation of NCPC charges distorts market incentives to engage in scheduling that can lead to real-time deviations. Unfortunately, this distortion is compounded by the fact that NCPC charges are allocated to real-time deviations that actually help reduce NCPC charges such as virtual load and over-scheduling of load in the day-ahead market. Over-allocating NCPC charges to real-time deviations has provided strong disincentives for participation by virtual traders in the ISO-NE market as discussed earlier in this section.

F. Conclusions and Recommendations

In our assessment of day-ahead NCPC charges, we found that 70 percent was attributable to commitments for local second contingency protection, while 23 percent was attributable commitments for the system-level 10-minute spinning reserve requirement. Both of these requirements are satisfied by scheduling operating reserves, but operating reserves are not procured in the day-ahead market and the cost of scheduling operating reserves is not reflected efficiently in energy prices. The absence of a co-optimized day-ahead operating reserve market resulted in:

- Excess commitments by the day-ahead market model for local second contingency protection in Boston, 75 percent of which would not have been needed under a co-optimized energy and reserve market.
- Depressed clearing prices for energy and 10-minute spinning reserves providers. We estimate there were 4,300 hours when additional generation was committed to satisfy the system level 10-minute spinning reserve requirement, which was not reflected in prices.

In addition, we continue to find that NCPC costs are inflated when the ISO is compelled to start combined-cycle resources in a multi-turbine configuration when its reliability needs could have been satisfied by starting them in a single-turbine configuration.

We make two recommendations to improve the pricing of energy and operating reserves.

- We recommend that the ISO co-optimize the scheduling and pricing of operating reserves in the day-ahead market.
- We recommend the ISO expand its authority to commit combined-cycle units in a single-turbine configuration when that will satisfy its reliability need.

One advantage to co-optimizing the scheduling of energy and operating reserves in the day-ahead market is that it would facilitate the elimination of the forward reserve market. As in prior years, nearly all of the resources assigned to satisfy forward reserve obligations in 2016 were fast-start resources capable of providing offline reserves. The value of the forward reserve market is questionable because:

- It has not achieved its objective to lower NCPC by purchasing forward reserves from high-cost units frequently committed for reliability.

- The forward procurements do not ensure that sufficient reserves will be available during the operating day.

The obligation of forward reserve suppliers to offer at prices higher than the Forward Reserve Threshold Price can distort the economic dispatch of the system and inefficiently raise costs.

In assessing the real-time NCPC charges, we found that 5 percent were for local reliability and 9 percent were for system level capacity requirements, while the vast majority were associated with inconsistencies between the output of economically scheduled generators and clearing prices in the real-time market. We find that three of the four largest categories of real-time NCPC charges have been addressed by three significant market improvements implemented in early 2017. These market improvements will not only lower real-time NCPC charges, but they will also result in much more efficient real-time prices that provide better performance incentives.

However, given that less than ten percent of the real-time NCPC can be attributed to real-time deviations, we find that ISO-NE currently over-allocates real-time NCPC charges to virtual transactions and other real-time deviations. This has substantially reduced virtual trading activity and the overall liquidity of the day-ahead market. Hence, we recommend that the ISO modify the allocation of Economic NCPC charges to be more consistent with a "cost causation" principle, which would largely involve not allocating NCPC costs to virtual load and other real-time deviations that do not cause it.

IV. External Interface Scheduling

Wholesale markets facilitate the efficient use of both internal resources and transmission interfaces between control areas. The latter is beneficial because it allows:

- Low-cost external resources to compete to serve consumers who would otherwise be limited to higher-cost internal resources;
- Low-cost internal resources to compete to serve load in adjacent areas; and
- ISO-NE to draw on neighboring systems for emergency power, reserves, and capacity that helps lower the costs of meeting reliability standards.

ISO-NE receives imports from Quebec and New Brunswick in most hours. Between New England and New York, power can flow in either direction depending on market conditions, although ISO-NE imported more power from NYISO than it exported in the past several years. The transfer capability between New England and adjacent control areas is large (relative to the New England's load), making it particularly important to schedule interfaces efficiently.

This section evaluates the following three aspects of transaction scheduling between New England and neighboring control areas:

- Scheduling patterns between New England and adjacent areas;
- Overall efficiency of scheduling between New England and New York; and
- Performance of Coordinated Transaction Scheduling with New York.

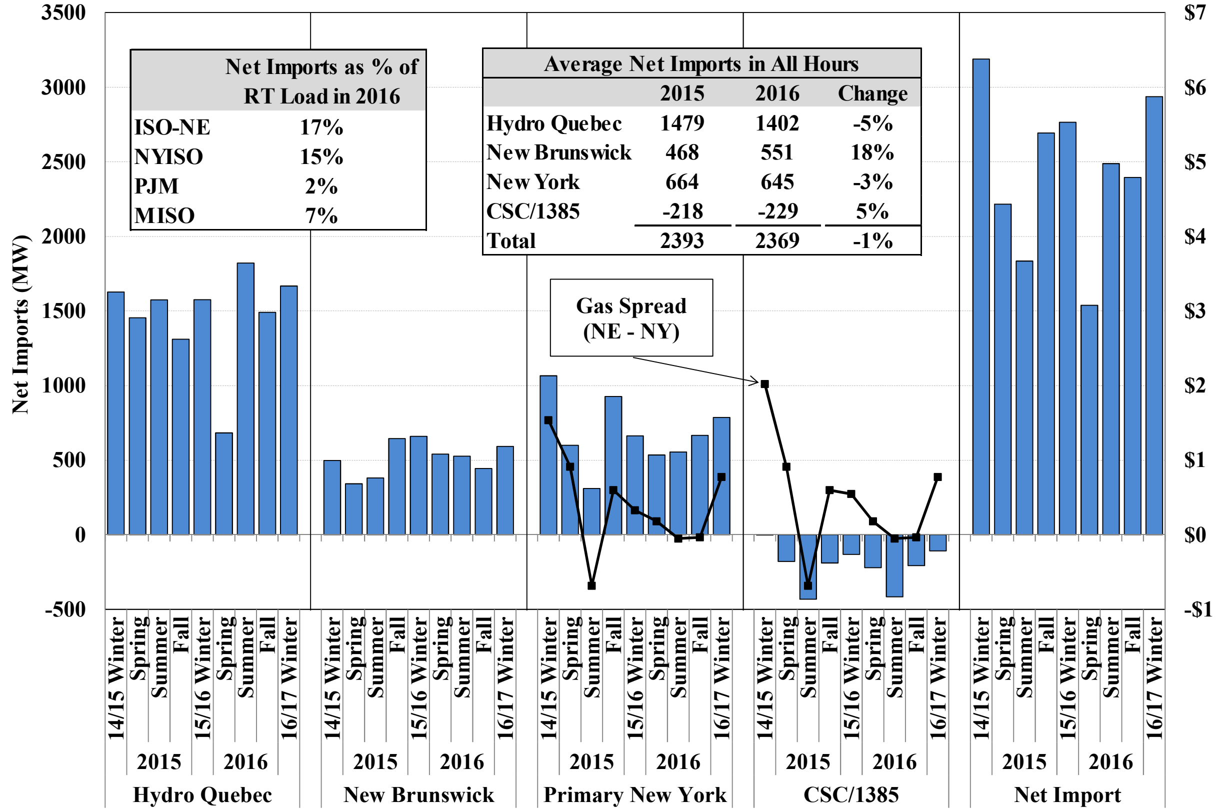
A. Summary of Scheduled Imports and Exports

This subsection summarizes the patterns of ISO-NE's imports and exports. Figure 9 provides an overview of imports and exports for 2015 and 2016, which shows the hourly average net imports by season across the external interfaces with Quebec, New Brunswick, and New York.[60] The net imports across the two interfaces linking Quebec to New England (i.e., Phase I/II and Highgate) are combined. The net imports across the two interfaces between Connecticut and Long Island (i.e., Cross Sound Cable and the 1385 Line) are combined as well. The figure shows the average spreads in natural gas prices (in black lines) between New England and New York across their three interfaces. [61]

60 The figure shows a nine-season period from December 2014 to February 2017.

61 Gas indices reported by Platts are used to calculate the spread between New England and New York. On the New York side, gas indices for Iroquois Zone 2 are used for the CSC/1385 interfaces and the higher of gas indices for Iroquois Zone 2 and for Transco Zone 6 NY (plus a 7% NYC tax) are used for the primary interface. On the New England side, gas indices for Algonquin City Gates are used for all three interfaces.

Figure 9: Average Net Imports from Neighboring Areas
By Season, 2015 – 2016



Net imports to New England averaged 2.4 GW in 2016, consistent with 2015. Net imports satisfied roughly 17 percent of real-time load in New England, modestly higher than the 15 percent in New York and significantly higher than the 2 to 7 percent in PJM and MISO markets. During periods of high imports from New York, New England has relied on imports to serve more than 20 percent of its load in some months. The reason that New England (and New York) rely more on imports than most other US markets is because of their close proximity to low-price Canadian markets. Additionally, natural gas pipeline limitations lead to higher production costs from gas-fired generation in New England, which attracts higher levels of electricity imports. This highlights the importance of efficient interchange scheduling with neighboring areas.

Although the interfaces with Quebec were often fully utilized to import to New England, average net imports from Quebec were generally higher in the peak seasons (i.e., summer and winter). This reflected the tendency for hydro resources in Quebec to store water during low demand (low profit) periods in order to make more power available during high demand (high profit) periods. This pattern is beneficial to New England because it tends to smooth the residual demand on New England internal generating resources.

Flows across the primary interface with upstate New York and the two controllable interfaces with Long Island exhibited a seasonal pattern, which was strongly correlated with the spreads in natural gas prices between the two markets. New England imported significantly more power across the primary interface from upstate New York (and exported less power across the two controllable interfaces to Long Island) in the winter months for several reasons:

- First, New England is more reliant on natural gas generation, which is typically most expensive in the winter months.
- Second, the spread in natural gas prices between New England and eastern New York tends to increase in the winter months because of rising demand for heating. The gas spreads between New England and New York averaged roughly $1.00 per MMBtu in the winter but only $0.15 per MMBtu during the other seasons over the past two years.

B. Efficiency of Interface Scheduling Between New England and New York

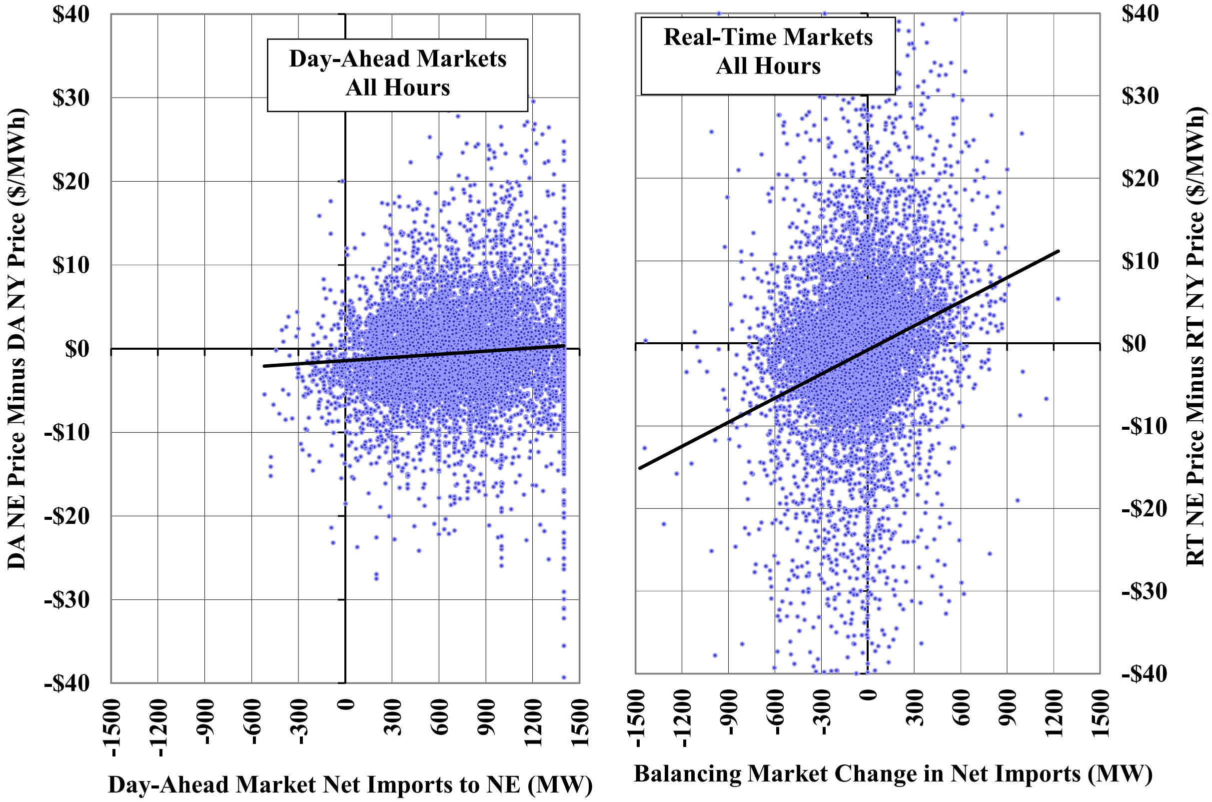
Since both New York and New England have real-time energy markets, market participants can schedule interchange transactions based on transparent real-time prices in each region. This subsection evaluates whether transactions were scheduled efficiently, consistent with the relative prices in the two regions.

Figure 10 shows a scatter plot of net scheduled flows across the primary interface versus the hourly difference in prices between New England and upstate New York in 2016. The left panel shows price differences in the day-ahead market on the vertical axis versus net imports scheduled in the day-ahead market on the horizontal axis. The right panel shows hourly price differences in the real-time market on the vertical axis versus the *change* in the net scheduled imports after the day-ahead market on the horizontal axis.[62]

The trend lines in the left and right panels show statistically significant positive correlations between the price difference and the direction of scheduled flows in the day-ahead and real-time markets. However, the correlation in the day-ahead market is relatively weak, which indicates the difficulty participants have in scheduling transactions efficiently. The correlation is stronger in the real-time market, and market participants generally respond to price differences by increasing net flows scheduled into the higher-priced region. Such real-time adjustments across the primary interface resulted in over $7 million of savings in production costs in 2016.

62 For example, if day-ahead net scheduled imports for an hour are 300 MW and real-time net scheduled imports are 500 MW, the change in net scheduled imports after the DAM would be 200 MW (= 500 – 300).

Figure 10: Efficiency of Scheduling in the Day-Ahead and Real-Time
Primary Interface Between New England and New York, 2016



However, the figure also shows that the response of market participants to inter-area price differences was incomplete. In 2016, the real-time response to the price difference was ultimately in the wrong direction (*from* the high-priced areas *to* the low-priced area) in 41 percent of the intervals. This highlights the fact that the external transmission interfaces could be utilized more effectively. The difficulty of predicting changes in market conditions in real-time (because of uncertainty and other costs and risks) interferes with efficient interchange scheduling, which underscores the value of having well-functioning a Coordination Transaction Scheduling process.

C. Evaluation of Coordinated Transaction Scheduling with New York

Coordinated Transaction Scheduling ("CTS") was implemented with the NYISO on December 15, 2015. In this process, the NYISO and ISO-NE operators exchange and use real-time market information to schedule market participants' external transactions more efficiently.[63] The CTS

63 ISO-NE provides a forecasted supply curve to NYISO every 15 minutes, which the NYISO uses to schedule CTS transactions. The NYISO's scheduling model ("RTC") evaluates whether to schedule a CTS bid to import assuming it has a cost equal to the sum of: (a) the CTS bid and (b) ISO-NE's forecasted marginal price. Likewise, RTC evaluates whether to schedule a CTS bid to export assuming it is willing to export at a price up to the sum of: (a) the bid and (b) ISO-NE's forecasted marginal price.

intra-hour scheduling system has at least three advantages over the hourly price-based scheduling system that was used previously.

- CTS bids are evaluated relative to the neighboring ISO's short-term price forecast, while the previous system required market participants to forecast prices in the adjacent market (more than 75 minutes in advance).
- The CTS process schedules transactions much closer to the operating time. Previously, schedules were established 45 to 105 minutes in advance, while schedules are now determined 15 minutes ahead when more accurate system information is available.
- Interface flows can be adjusted every 15 minutes instead of every 60 minutes, which allows for much quicker response to real-time events.

It is important to evaluate the performance of CTS on an on-going basis so that the process can be made to work as efficiently as possible. This subsection evaluates the following aspects of the performance of CTS during the first year of its implementation:

- Efficiency of the scheduling patterns and the accuracy of the forecasted prices;
- Liquidity of the CTS bids;
- Whether "Tie Optimization" would have performed better than CTS, and
- An evaluation of the forecast errors in the CTS process.

In these analyses, the performance of CTS between ISO-NE and the NYISO is sometimes benchmarked against the performance of CTS between PJM and the NYISO.

Evaluation of Scheduling Efficiency of CTS Process

The first analysis evaluates the overall efficiency of the CTS scheduling process (relative to our estimates of the scheduling outcomes that would have occurred under the previous hourly scheduling process). This evaluation provides an indication of the degree to which the CTS process has improved scheduling outcomes at the NE/NY interface in 2016.

To estimate the adjustment in the interchange schedule attributable to the intra-hour CTS scheduling process, we first estimate the hourly interchange schedule that would have flowed without the CTS based on the advisory schedules in NYISO's RTC model.[64] We than evaluate the efficiency of these adjustments. This section shows our evaluation of the NY/NE CTS process in comparison to the results of the NY/PJM CTS process. Table 3 shows the market efficiency gains (and losses) from the two CTS processes in 2016, which is measured by production cost savings. The table shows the following breakdowns of the savings:

64 RTC is the NYISO's real-time commitment engine used to schedule CTS transactions and other external transactions. RTC determines hourly schedules at 15 minutes past previous hour, while determining advisory schedules for future periods. Our evaluation uses these advisory schedules to estimate the hourly schedules that would have occurred without CTS by taking the average of the four advisory quarter-hour schedules that RTC produced for each hour.

- Projected Savings at Scheduling Time – This measures the expected production cost savings at the time when RTC determines the interchange schedule across the interface.
- Net Over-Projected Savings – This estimates the portion of savings that were inaccurately projected because of PJM, NYISO, and ISO-NE forecast errors.
- Unrealized Savings – This estimates production cost savings that are not realized because of the following factors:
  - Real-time Curtailment - Some of RTC scheduled transactions may be curtailed for various reasons (e.g., real-time cuts for reliability). The reduction of flows in the efficient direction reduces market efficiency gains.
  - Interface Ramping – The price forecasting engine and real-time dispatch model in each market (e.g., CTSPE and UDS in ISO-NE) assume different timing for interface schedules to ramp in, which leads a portion of projected savings to be unrealized.
  - Price Curve Approximation – CTSPE forecasts a 7-point piecewise-linear supply curve and transforms it into a step-function for use in CTS. This causes the CTS scheduling to not be fully consistent with ISO-NE's marginal cost of interchange.

These efficiency results are shown separately for periods with larger errors in the price forecasts (>$20/MWh) and smaller forecast errors. In addition to the efficiency results, the table shows the size and frequency of the adjustments:

- % of All Intervals – This shows the percent of quarter-hour intervals during which the interface flows were adjusted by CTS (relative to the estimated hourly schedule).
- Average Flow Adjustment – The estimated CTS adjustment where positive values indicate adjustments from PJM or New England to New York and negative numbers indicate adjustments from New York to PJM or New England.

Table 6: Efficiency of Intra-Hour Scheduling Under CTS
Primary NE/NY and PJM/NY Interfaces, 2016

			Average/Total During Intervals w/ Adjustment					
			CTS - NE/NY			CTS - PJM/NY		
			Both Forecast Errors <= $20	Any Forecast Error > $20	Total	Both Forecast Errors <= $20	Any Forecast Error > $20	Total
% of All Intervals w/ Adjustment			75%	11%	**87%**	54%	7%	**61%**
Average Flow Adjustment (MW)	Net		-0.3	-2	**-0.5**	13	25	**14**
	Gross		73	101	**76**	59	101	**64**
Production Cost Savings ($ Million)	Projected at Scheduling Time		$2.4	$2.1	**$4.5**	$0.9	$2.2	**$3.1**
	Net Over-Projection by:	NY	-$0.02	-$0.3	**-$0.3**	-$0.1	-$1.7	**-$1.9**
		NE or PJM	-$0.1	-$1.0	**-$1.1**	-$0.1	-$0.6	**-$0.7**
	Unrealized Savings		-$0.4	-$0.7	**-$1.1**	-$0.04	-$0.6	**-$0.7**
	Actual Savings		$1.9	$0.1	**$2.0**	$0.6	-$0.8	**-$0.1**

Our analyses show that $4.5 million and $3.1 million of production cost savings were projected at the time of scheduling at the primary NE/NY and PJM/NY interfaces in 2016. However, only an estimated $2 million of savings were realized at the NE/NY interface and no savings were realized at the PJM/NY interface. The reduction in the actual savings were largely caused by price forecast errors. The table shows that reduction in savings was much larger in periods when the forecast errors exceeded $20 per MWh, which such reductions were much smaller when the forecast errors were less than $20 per MWh. Therefore, improvements in the CTS process should focus on identifying sources of forecast errors (which are discussed later in this subsection). Most of the remaining loss in savings were unrealized because of the three factors described above.

Finally, our evaluation likely under-estimates both projected and actual savings because our methodology for identifying the base level of interchange (absent the CTS adjustments) will inevitably include some CTS transactions and the associated savings. Nonetheless, these results remain useful for identifying sources of inefficiency in the CTS process.

Evaluation of CTS Bidding Patterns

CTS requires traders to submit bids that will be scheduled only when the RTOs' forecasted price spread is greater than the bid price, so the process requires a substantial quantity of price-sensitive bids. Figure 11 evaluates the price-sensitivity of bids at the NE/NY and PJM/NY interfaces, showing the average amount of bids at each interface during peak hours (i.e., HB 7 to 22) by month. Positive numbers indicate export bids from New England or PJM to New York and negative numbers represent import offers from New York to New England or PJM.

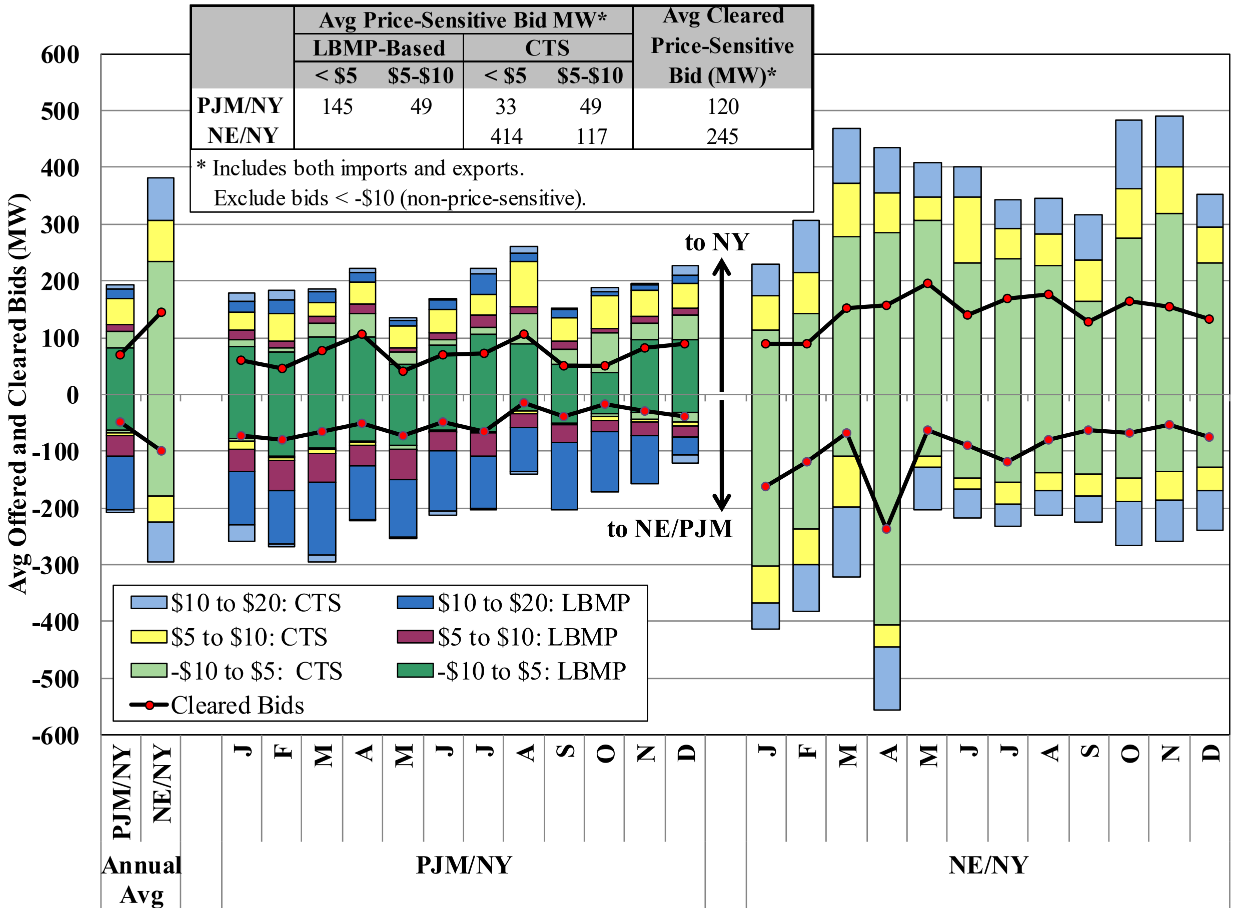
The bars show the average quantities of price-sensitive CTS bids (bids offered between -$10 and $20 per MWh) for three price ranges.[65]

Only CTS bids are allowed at the NE/NY interface, while both CTS bids and price-based bids are allowed at the PJM/NY interface. Thus, the figure also shows price-based bids relative to the short-term forecast so that the liquidity of bids at the two interfaces can be directly compared.[66] The two black lines in the chart indicate the average scheduled price-sensitive CTS imports and exports (including price-based bids for NY) in each month. The inset table in the figure summarizes the aggregate quantities of price-sensitive bids at each interface, along with the average quantity of cleared transactions.

65 RTC evaluates whether to schedule a CTS bid to import assuming it has a cost equal to the sum of: (a) the bid price and (b) NE's or PJM's forecast marginal price. Likewise, RTC evaluates whether to schedule a CTS bid to export assuming it is willing to export at a price up to: (a) NE's or PJM's forecast marginal price less (b) the bid price.

66 For example, if the short-term price forecast in PJM is $27, a $5 CTS bid to import would be scheduled if the NYISO price forecast is greater than $32. Likewise, a $32 price-based import offer would be scheduled under the same conditions. Thus, the LBMP-based offer would be shown in the figure as comparable to a $5 CTS import bid.

Figure 11: Average CTS Transaction Bids and Offers by Month
Primary NE/NY and PJM/NY Interfaces - 2016



Although the CTS process at the NE/NY interface is relatively new, participation is much more active than at the PJM/NY interface. The average amount of price-sensitive bids submitted at the NE/NY interface is significantly higher than those at the PJM/NY interface. In 2016, price-sensitive offers at the NE/NY interface averaged 531 MW, nearly double the amount offered at the PJM/NY interface. Likewise, the cleared price-sensitive bids at the NE/NY interface were more than double the amount cleared at the PJM/NY interface. As a result, the interchange schedules were adjusted more frequently between New York and New England and higher savings were achieved (as shown in Table 3).

These differences between the CTS processes are largely attributable to the large fees that are imposed at the PJM/NY interface, which range from $2 to $8 per MWh. There are no fees charged or costs allocated to transactions between New York and New England, which was a very good decision from a design perspective. However, if the ISO's can improve the price forecasts that underlie the CTS prices, the risks facing participants submitting CTS transactions will be reduced. This should improve both the quantity and the price-sensitivity of the CTS bids, and ultimately allow the process to achieve larger savings.

Expected Performance of the Tie Optimization Alternative

When ISO-NE and NYISO considered market design changes to improve interchange scheduling between the two markets, two options emerged: CTS and Tie Optimization. Unlike CTS, Tie Optimization would adjust interchange based only on the ISO's forecasts without trader participation. Although CTS was adopted, the ISOs' joint proposal included a process (and trigger) for switching to Tie Optimization if warranted.[67] This subsection evaluates whether Tie Optimization would likely have performed better than CTS at the primary NE/NY interface during the first year of implementation.

As required by the ISOs' joint proposal to adopt CTS, we developed an analysis that estimates the savings of the Tie Optimization alternative. Specifically, this analysis compared two scenarios:[68]

- A Tie Optimization scenario – Interchange that would have occurred if the ISOs had an infinite number of zero bids given the ISOs' actual price forecasts; and
- An Optimal Interchange scenario – Interchange that would have occurred if the ISOs had an infinite number of zero bids assuming perfect price forecasts;.

Table 7 shows the estimated production cost savings in 2016 for the Optimal Interchange ("OI") and Tie Optimization ("TO") cases for intervals where the cases would make the same adjustment, or when the TO case would deviate from the OI case in the following ways:

- Over-Adjustment: (a) TO over-adjusts the interchange in the same direction as OI, or (b) TO adjusts but OI does not.
- Under-Adjustment: (a) TO under-adjusts the interchange in the same direction as OI, or (b) OI adjusts but TO does not.
- Adjustment in Wrong Direction: TO adjusts in the opposite direction as OI.

67 See NYISO MST Section 31 Attachment P – Coordinated Transaction Scheduling with ISO New England; Actions, Thresholds and Triggers.

68 The assumptions and methodologies adopted in our analysis can be found in the presentation *First Year Evaluation of CTS between New England and New York* to Joint ISO-NE/NYISO Stakeholder Meeting on April 20, 2017.

Table 7: Estimated Production Cost Savings for TO and OI
By Category of Interchange Adjustment, 2016

Category of Adjustment		Production Cost Savings ($M) Tie Optimization (TO)	Production Cost Savings ($M) Optimal Interchange (OI)	% of 5-Minute Intervals
No Adjustment				20%
Same Adjustment		$0.7	$0.7	6%
Over Adjustment	Same Direction as OI	-$0.1	$0.1	10%
	No OI Adjustment	-$0.5		9%
Under Adjustment	Same Direction as OI	$0.8	$1.7	18%
	NO TO Adjustment		$2.3	24%
Adjustment in Wrong Direction		-$1.3	$1.0	13%
Total		**-$0.3**	**$5.8**	**100%**

We estimate that, in 2016, Tie Optimization would result in an *increase* of $0.3 million in regional bid production costs (relative to the current CTS process), while the Optimal Interchange would *reduce* these costs by $5.8 million. Although this assessment for Year One is only for advisory purposes, these results are well below the trigger defined in the Tariff for potentially moving to Tie Optimization.[69]

Forecast errors were the primary reason that Tie Optimization would have raised costs. The table shows that Tie Optimization would result in the same interchange adjustments and benefits as Optimal Interchange in only 26 percent of the intervals in 2016. In the remaining 74 percent of intervals, Tie Optimization would lead to reduced or often *negative* savings from sub-optimal adjustments because of forecast errors. Forecast errors are evaluated in greater detail in the next part of this subsection.

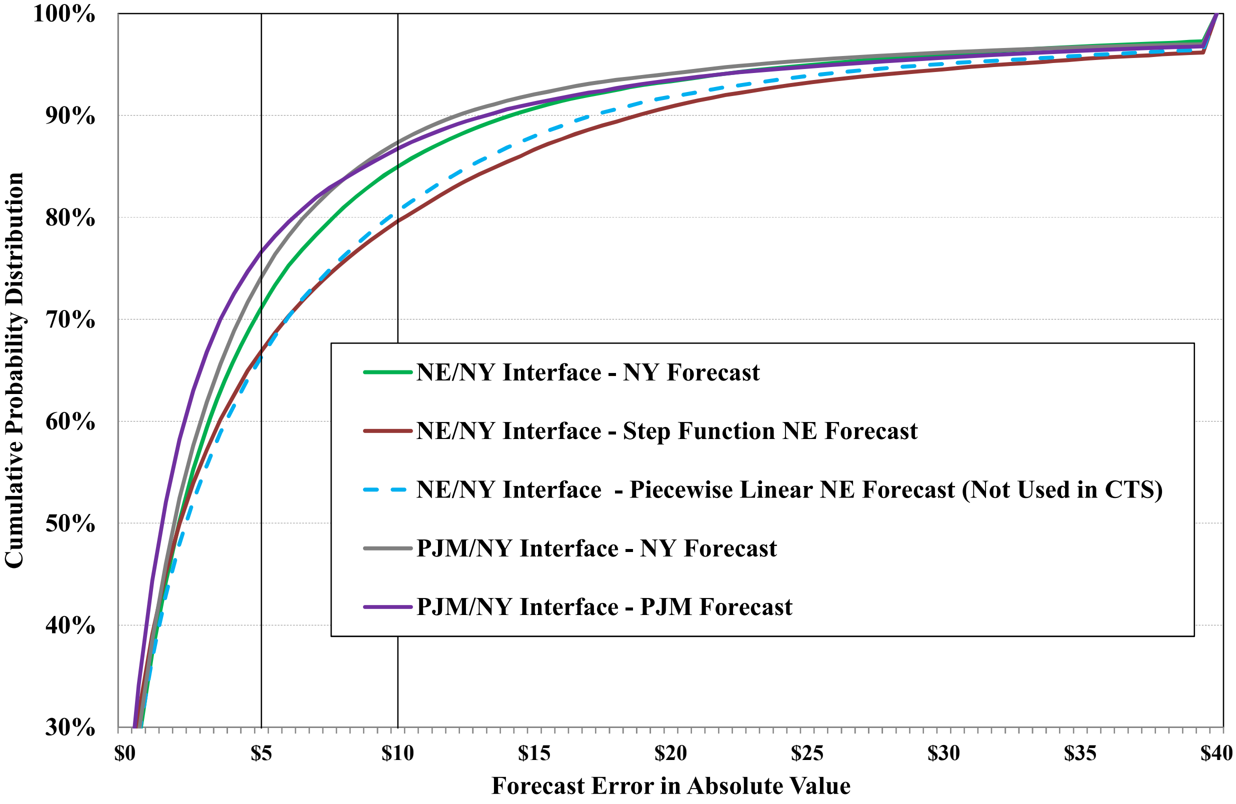
Performance of Price Forecasting

The next analysis compares the performance of price forecasting by the three ISOs in the CTS process. Figure 12 shows the cumulative distribution of forecasting errors in 2016. The price forecast error in each 15-minute period is measured as the absolute value of the difference between the forecast price and actual price. The figure shows the ISO-NE forecast error based

69 The trigger requires that, for the second year of CTS implementation, : (i) the “foregone” bid production cost savings from implementing CTS rather than Tie Optimization is greater than $3 million; and (ii) the “foregone” savings from (i) is more than 60 percent of the “foregone” savings of implementing Tie Optimization rather than Optimal Interchange.

on the piecewise linear curve produced by its forecasting model, as well as based on the step-function that the NYISO model uses to approximate the piecewise linear curve.

Figure 12: Distribution of Price Forecast Errors Under CTS
NE/NY and PJM/NY Primary Interfaces, 2016

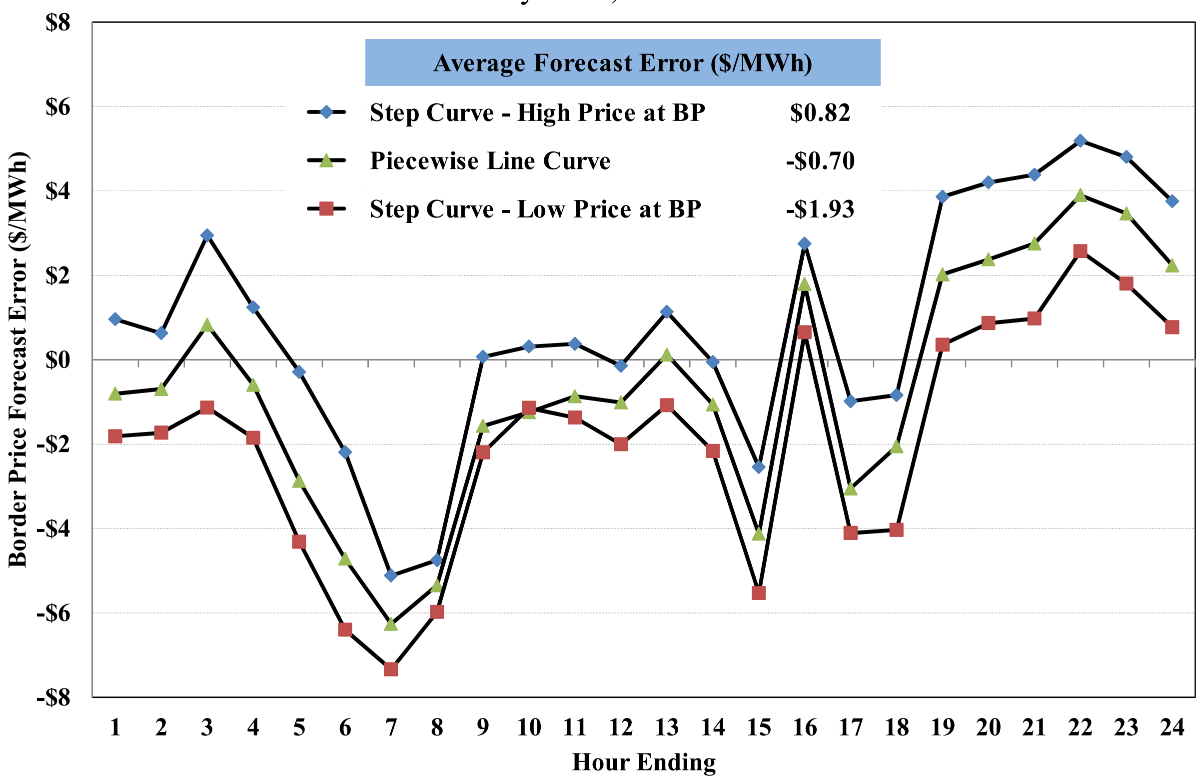


All of the forecasts show substantial errors, although the forecasting performance was slightly better at the PJM/NY interface than at the NE/NY interface in 2016. For example, price forecast errors were greater than $10/MWh in roughly 13 percent of intervals at the PJM/NY interface and 15 to 20 percent of the intervals at the NE/NY interface. The smaller errors at the PJM interface are likely due to the greater price-elasticity of supply in PJM because of its size and the lower overall prices. Nonetheless, these errors undermined the performance of the CTS at both interfaces and we are recommending each of the three RTO's focus on identifying and resolving price forecasting issues. Based on our preliminary assessment of the forecast errors in New England, we have identified the following factors that are likely contributing to its forecast errors.

Step-Function Approximation of ISO-NE Supply Curve. The price forecasting based on step-function approximation of ISO-NE's supply curve was similar in accuracy to its' piecewise linear curve when the forecast error was less than $10/MWh (roughly 80 percent of intervals). However, the divergence of the two supply curves is much larger in intervals exhibiting larger forecast errors, indicating that the step-function approximation is likely contributing to the larger forecast errors in these intervals. On January 5, 2016 for example, the CTS process scheduled interchange adjustments based on a forecasted price under step-wise curve of greater than $1000 per MWh where the linear curve would have produced a forecasted prices of $700 per MWh.

The largest deviations occur when adjustments are scheduled at one of the breakpoints in the step-wise curve. At the breakpoints, the price can be set at the top of the step or the bottom. The adjustments made at a breakpoint in 21 percent of intervals, but the effect on the forecast can be substantial. To illustrate this, Figure 13 shows the average forecast errors by CTSPE at the New England interface by hour in 2016, based on setting the price at the top of the step, bottom of the step, or on the piece-wise linear curve when at a breakpoint.

Figure 13: Average Forecast Errors Using Different Supply Curves
by Hour, 2016



Although these error curves are correlated, the forecast using the high price at the break point, which is the price currently used, exhibited an average *over-forecast* of $0.82/MWh in 2016. Since the NYISO tends to under-forecast on average, this observation suggested that NYISO and ISO-NE's forecasts were biased in the opposite directions, leading to over-scheduling of interchange from New York to New England.[70] However, the forecast using the low price at the break point yielded an average *under-forecast* of $1.93/MWh, which would be far worse. The most accurate forecast is produced by the piece-wise linear curve. If CTS system will not

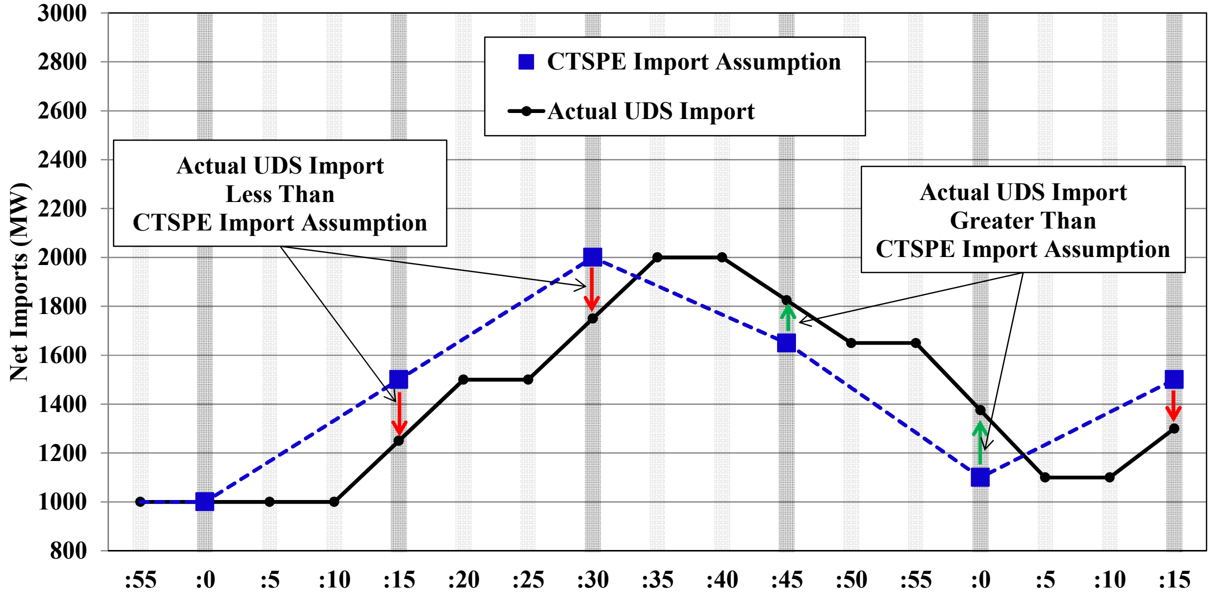
70 See *ISO New England's Internal Market Monitor 2016 Annual Markets Report*, Section 5.5.

accommodate the piece-wise linear curve, these results suggest that accuracy could be improved by increasing the number of points (i.e., price/quantity pairs) in the step-function, particularly on the portion with steep slopes.

Inconsistent Interface Ramp Profiles in CTSPE vs UDS. The analysis above also indicates that while ISO-NE under-forecasts on average. it under-forecasts most significantly during the morning ramp-up hours, and it over-forecasts during the evening ramp-down period. This pattern suggests that the forecasting model assumes larger amounts of ramp will be available than is actually available in the real-time dispatch model. When the forecast model over-estimates the ability of resources to ramp, it under-forecasts prices when resources are ramping-up, and it over-forecasts prices when resources are ramping-down. This indicates the importance of ramp assumptions and limitations in the forecasting process.

CTSPE provides a forecasted supply curve to the NYISO every 15 minutes into the future, and assumes that changes in imports and exports will ramp smoothly over the 15-minute period. Alternatively, UDS assume import and export changes will ramp over 10 minutes (from 5 minutes before the top of the 15-minute period to 5 minutes after). Figure 14 illustrates how this inconsistency can affect the assumed ramp effects of the interchange transactions, which will lead to price forecast errors. These errors are largest when interchange is change most rapidly, which unfortunately is also when the CTS adjustments promise the highest savings.

Figure 14: Illustration of External Transaction Ramping Profiles in CTSPE and UDS



The NYISO scheduling model (used to schedule CTS transactions) and the NYISO real-time dispatch model exhibit a similar inconsistency ramp assumptions. Hence, we recommend that both ISOs evaluate alternatives for reducing or eliminating these inconsistencies.

Generator Ramping Assumption in UDS. The real-time market software, UDS, is limited in its ability to anticipate near-term needs, and the system is often "ramp-constrained" (i.e., generators are moving as quickly as they can). The assumption regarding ramping capability of individual resources has a large impact in prices, particularly when the system is "ramp tight".

UDS assumes that each resource has a 15-minute ramping capability starting from its latest state estimator input. However, our analysis for 2016 indicates that the actual ramping time ranged from 10 to 18 minutes, and was within one minute of the assumption (i.e., from 14 to 16 minutes) in only 38 percent of UDS runs in 2016. When actual ramping time is less than the assumed ramping time, UDS tends to over-estimate the amount of available ramp. This inconsistency between actual ramp and assumed ramping in UDS may have significant effects on real-time prices, so we will continue to evaluate the effects of this issue on prices and on forecast error in the CTS process.

D. Conclusions and Recommendations

New England's interconnections with adjacent systems provides considerable economic benefits and reliability benefits. Overall, 17 percent of New England's demand was satisfied by net imports, primarily from Canada. Although average imports were lower from New York, the size of the primary interface with NYISO allowed New England to import up to 1.4 GW in many hours with tight conditions in New England.

The lines from Canada are often fully utilized because of low generating costs in those areas, so it not difficult to maximize the utilization of the interfaces with Quebec and New Brunswick. Generating costs are more similar between New York and New England, making it more difficult to predict the optimal scheduled interchange between NYISO and ISO-NE. We find that market participants scheduled interchange in the profitable direction on average between NYISO and ISO-NE, netting $7 million in the day-ahead market. However, we still found that real-time interchange was still scheduled in the unprofitable direction in 41 percent of intervals in 2016, and that market participants still bear significant risk when scheduling in the CTS process.

Based on a detailed study of the performance of CTS scheduling process between New York and New England, we make the following findings:

- The amount of price-sensitive CTS bids offered at the NE/NY interface was significantly higher than the amount submitted at the PJM/NY interface, the primary reason why much larger savings were realized at this interface. The diminished liquidity at the PJM interface is likely due to the large transactions fees imposed by NYISO and PJM.
- The CTS process has led to significant production cost savings, although less than haf of the projected savings were actually realized, primarily because of price forecast errors.

- The price forecast errors are large enough that moving to Tie Optimization would result in *higher costs* rather than higher savings.
- We identify several factors that are likely contributing to poor forecasting:
  - The CTS scheduling process uses a simplified representation of the ISO-NE's forecast supply curve.
  - Both the NYISO and ISO-NE forecast models use ramp timing assumptions for interchange that are inconsistent with their respective dispatch models. Figure 14
  - ISO-NE's real-time dispatch software (i.e., UDS) assumes a constant 15-minute ramp period that is sometimes inconsistent with the actual time available to ramp resources.

Although it is still early to draw strong conclusions, these results from the first year of implementation indicate a generally successful implementation of the CTS scheduling process between New England and New York. However, additional benefits will be realized if the ISOs can improve the accuracy of their price forecasts. Hence, we recommend that ISO-NE consider:

- Increasing the number of supply curve points that are used to model supply costs in the New England market, particularly in steep portions of the supply curve; and
- Modifying its real-time software to align ramping assumption with actual ramp capability.

We will continue monitor the performance of CTS and evaluate factors that contribute to forecast errors.

V. Appendix: Assumptions Used for Key Analyses

A. Estimation of Net Revenues for Gas-fired Units

The method we use to estimate net revenues for new gas units and older, existing fossil technologies uses the following assumptions:

- Fuel costs for all units are based on the Algonquin City Gates gas price index.
- All units are scheduled before each day based on day-ahead prices, considering commitment costs, minimum run times, minimum generation levels, and other physical limitations.
- CC and ST units may sell energy, 10-minute spinning reserves, and 30-minute reserves; while combustion turbines may sell energy and 10-minute or 30-minute non-spinning reserves. Each gas-only and dual-fueled unit is assumed to offer reserves, limited only by its ramp rate and commitment status.
- Combustion turbines (including older gas turbines) are committed in real-time based on hourly real-time prices. Combustion turbines settle with the ISO according to real-time market prices and the deviation from their day-ahead schedule.
- Online units are dispatched in real-time consistent with the hourly integrated real-time LBMP and settle with the ISO on the deviation from their day-ahead schedule. However, to account for the effect of the slower ramp rate of the ST unit in this hourly analysis, the unit is assumed to operate within a certain margin of the day-ahead energy schedule. The margin is assumed to be 25 percent of the maximum capability.
- All technology types are evaluated under gas-only and dual-fuel scenarios to assess the incremental profitability of dual-fuel capability. ST units are assumed to use low sulfur residual oil. All other units are assumed to use ultra-low sulfur diesel oil.
- Combustion turbines (including older gas turbines) are also evaluated for their profitability based on the generator's decision to participate in the Forward Reserve Auctions for each of the capability periods. It is assumed that generators anticipate when selling forward reserves will be more profitable than selling real-time reserves before each capability period.
- All the dual-fuel units are assumed to offer into the Winter Reliability Program (WRP). The revenues from WRP were estimated using the ISO-determined Set Rate that is paid as compensation for the per-barrel carrying costs of stored oil.
- Fuel costs assume transportation and other charges of 27 cents/MMbtu for gas and $2/MMbtu for oil on top of the day-ahead index price. Intraday gas purchases are assumed to be at a 20% premium due to gas market illiquidity and balancing charges, while intraday gas sales are assumed to be at a 20% discount for these reasons.
- The minimum generation level is 262 MW for CCs and 90 MW for ST units. The heat rate is 7,498 btu/kWh at the minimum output level for CCs, and 13,000 btu/kWh for ST

units. The heat rate and capacity for a unit on a given day are assumed to vary linearly between the summer values on August 1 and the winter values on February 1. The summer and winter values are shown in the following two tables.

- Regional Greenhouse Gas Initiative (RGGI) compliance costs are included.
- We estimate the net revenues from capability year 2017/18 to 2020/21 using forward prices for power, natural gas, ULSD and FCA clearing prices.[71] We held the reserve prices for future years at their 2016 levels.
- We also use the modified operating and cost assumptions listed in the following tables:

Table 8: New Unit Parameters for Net Revenue Estimates [72]

Characteristics	CC 1x1	CT - 7HA
Summer Capacity (MW)	515	331
Winter Capacity (MW)	551	345
Summer Heat Rate (Btu/kWh)	6546	9220
Winter Heat Rate (Btu/kWh)	6460	9052
Min Run Time (hrs)	4	1
Variable O&M ($/MWh)	$3.5	$1.0
Startup Cost ($)	$0	$16,148
Startup Cost (MMBTU)	4000	391
EFORd	3.0%	2.2%

Table 9: Existing Unit Parameters for Net Revenue Estimates

Characteristics	ST	GT-30
Summer Capacity (MW)	360	16
Winter Capacity (MW)	360	20
Heat Rate (Btu/kWh)	10000	17000
Min Run Time (hrs)	16	1
Variable O&M ($/MWh)	$8.0	$4.5
Startup Cost ($)	$6,000	$519
Startup Cost (MMBTU)	2000	60
EFORd	5.1%	19.7%

71 We used the average of daily internal Hub forward prices over the trade period of January 2017 through March 2017.

72 These parameters are based on technologies studied as part of the ISO’s demand curve filing.

B. Estimation of Net Revenues for Nuclear Units

Our estimates for the net revenues the market would have provided to existing nuclear units are based on the following assumptions:

- Nuclear plants are dispatched day ahead and may only sell energy and capacity.
- The energy revenue estimates for the past years are based on the Hub LMPs. For future years, the estimates are based on energy price futures for the Hub.
- Nuclear units earn energy revenues throughout the year except during periods of forced outages and outages related to refueling. We assumed an EFORd of two-and-a-half percent, and a capacity factor of 75 percent during March, April, October, and November to account for reduced output during refueling.[73]
- The costs of generation (including O&M, fuel, and capex) for nuclear plants are highly plant-specific and vary significantly based on several factors that include number of units at the plant, technology, age and location. Our assumptions for operating costs for single and multi-unit nuclear plants are based on observed average costs of nuclear plants in the US.[74]

C. Estimation of Net Revenues for Renewable Resources

We estimated the net revenues the markets would have provided to utility-scale solar PV,onshore wind plants, and offshore wind plants in ISO-NE using the following assumptions:

- Net E&AS revenues are calculated using real time energy prices.
- The energy produced by these units is calculated using technology and location-specific hourly capacity factors for each month. The capacity factors are based on location-specific resource availability and technology performance data from NREL's 2016 Annual Technology Baseline 2016.
- The capacity revenues for solar PV, onshore wind plants and offshore wind plants in every year are calculated using prices from the corresponding FCAs. The capacity values of solar PV, onshore wind and offshore wind plants are based on the average ratio of qualified capacity to the nameplate rating (16, 30 and 35 percent, respectively).[75]
- We estimated the value of RECs produced by utility-scale solar PV, onshore wind and offshore wind units using the MA Class I REC Index values from SNL Financial. Future REC prices were assumed to remain constant at the posted index level as of March 17,

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73 The refueling cycle for nuclear plants in New England is typically 18 months. We assume reduced capacity factors in the Spring (April and May) and in the Fall (October and November) every year in order to enable a year over year comparison of net revenues.

74 The average cost of operation of nuclear plants in the US are based on NEI/ EUCG reports and presentations. See http://www.nei.org/Issues-Policy/Economics/Financial-Analyst-Briefings and http://www.nei.org/CorporateSite/media/filefolder/Policy/Papers/statusandoutlook.pdf?ext=.pdf.

75 The solar and onshore wind factors are from the ISO-NE CONE and ORTP analysis.

2017. This assumed REC price of $26.50/MWh for the future years is consistent with the REC price that was assumed in CONE and ORTP study.

- Solar PV and onshore wind plants, as renewable projects, are eligible for Investment Tax Credit ("ITC") and Production Tax Credit ("PTC") respectively as part of federal programs to encourage renewable generation. The ITC reduces the federal income tax of the investors by an amount equal to 30 percent of a solar PV unit's eligible investment costs and is realized in the first year of the project's commercial operation. The PTC is a per-kWh tax credit for the electricity produced by a wind facility over a period of 10 years.[76] We assume construction lead time of 1 year for solar PV plant, 2 years for onshore wind plant and 3 years for offshore wind plant. As such, in accordance with the scheduled phase-down of federal incentives, the value of ITC for solar PV drops in 2020/21, while the PTC value for onshore wind units decreases beginning 2019/20.
- The cost of developing new renewable units, especially solar PV plants, has dropped rapidly over the last few years. The estimated investment cost for solar PV technologies varies significantly based on the study methodology and study period. Table 10 shows our assumed costs and other operating for solar PV and onshore wind units. The data shown are based on cost and regional multiplier estimates from NREL.[77] The table also presents the operating and cost assumptions we used for calculating net revenues for utility-scale solar PV, onshore wind plants, and offshore wind plants.

[76] The ITC is 30% of the total eligible investment costs for projects that commence construction by end of 2019. It is scheduled to step down to 26% for projects starting construction in 2020 and 22% for projects starting construction in 2021. The Production Tax Credit is also scheduled to be phased out through 2019 and only wind facilities that commence construction prior to December 31, 2019 are eligible for this credit. The PTC is available only for the first 10 years of the project life. The value of PTC shown is levelized on a 20-year basis using the after-tax WACC. In addition to these federal incentives, renewable power projects may qualify for several other state or local-level incentives (for instance, property tax exemptions) in New England. However, our analysis does not consider any other renewables-specific revenue streams or cost offsets beyond the revenues from sale of RPS attributes and the PTC or the ITC offset.

[77] Cost and other operating data is taken from NREL , 2016, *Annual Technology Baseline and Standard Scenarios*, See: http://www.nrel.gov/analysis/data_tech_baseline.html. The reported investment cost includes the following spur line interconnection cost:

a) Solar PV: $99/kW

b) Onshore Wind: $46/kW for Massachusetts and $26/kW for Maine

c) Offshore Wind: $607/kW (Includes only the offshore spur line cost for a 30 km transmission line)

This interconnection cost data is taken from the input data used by NREL in ReEDS modeling analyses. Regional multipliers are taken from NREL's input in their ReEDS modeling analyses.

Table 10: Utility-Scale Solar and Onshore Wind Parameters for Net Revenue Estimates

Parameter	Utility-Scale Solar PV	Onshore Wind	Offshore Wind
Investment Cost (2016$/kW AC basis)	$2529 ($1797 low to $3043 high)	Massachusetts: $2549 ($1917 low to $2718 high) Maine: $2431 ($1898 low to $2774 high)	$7,233
Fixed O&M (2016$/kW-yr)	$19 ($15 low to $22 high)	$53 ($33 low to $53 high)	$120
Federal Incentives	ITC (30%)	PTC ($23/MWh)	ITC (30%)
Variable O&M ($/MWh)	-	-	-
Project Life	20 years		
Property Tax	1.00%		
Depreciation Schedule	5-years MACRS		
Average Annual Capacity Factor	18%	Massachusetts: 37% Maine: 45%	50%

D. Estimation of Net Revenues for Hydropower Imports from Canada

A substantial share of Hydro Quebec's (HQ) electricity supply originates from hydroelectric reservoirs. HQ regularly exports power to the adjacent markets of the IESO, NYISO and ISO-NE, to which it is connected by several High-voltage Direct Current (HVDC) transmission lines. The controllable nature of the hydropower and HVDC projects enable HQ to control for the time and destination of its electricity imports. Our estimates for the energy net revenues of a new 1100 MW HVDC line operator importing hydropower from Canada to ISO-NE are based on opportunity cost-based modeling framework. In a given year, our methodology for estimating the energy net revenues uses the following assumptions:

- The HVDC transmission line operator would export to power during the hours when the LBMP it would receive is greater than the expected cost of purchasing power in HQ plus the applicable transmission service charge.
- We estimated the total quantity of energy available for export to HQ's adjacent control areas by adjusting HQ's annual exports during 2016 by the annual load growth and the planned resource additions during (i.e. from 2016 to 2021).[78,79]

78 Our assumption for HQ's net exports in 2016 is based on commodity statistics presented on the National Energy Board website at https://apps.neb-one.gc.ca/CommodityStatistics/Statistics.aspx?language=english. HQ's forecasted capacity additions are listed on page 120 of NERC's 2016 Long-Term Reliability Assessment, available at http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2016%20Long-Term%20Reliability%20Assessment.pdf. We assumed that HQ's load growth will increase by 0.4%. See http://news.hydroquebec.com/en/press-releases/1131/hydro-quebec-anticipates-moderate-growth-in-electricity-demand-over-next-10-years/

79 HQ has the ability to import electricity from the Ontario region for sale across HQ's other interfaces. In recent years, Quebec has imported significant quantities of power from Ontario, which has led to increased exports to New York and New England (and to Ontario in higher priced hours). Accordingly, we incorporated opportunities to import from Ontario into the model.

- The LBMPs for future years at the locations where HVDC lines deliver power were estimated using the forward prices as observed during January 2017 through March 2017.
- The HQ region does not have a centralized wholesale spot market for electricity, so there are no transparent publicly-available spot prices that can be used to estimate the cost of purchasing electricity for export across the HVDC lines. Therefore, we estimated the cost of purchasing electricity in HQ based on spot prices in markets adjacent to the HQ region. We estimated the average marginal cost of purchasing electricity in HQ in the following manner:

  For each neighboring market in each hour during a given year, we determined the revenue that a marketer could earn from exporting from the HQ region. For example, in an hour when the price in ISO New England was \$50/MWh and the transmission service charge was \$10/MWh, a \$40/MWh revenue opportunity would be reflected in an "export opportunity curve" for a quantity of megawatt-hours equal to the TTC of the interface in that hour. The total amount of electricity available for export over a given year was combined with an "export opportunity curve" to determine the marginal cost of purchasing electricity for export.
- The maximum amount of electricity that can be transmitted across HQ's interfaces in any given hour is based on the Total Transfer Capabilities ("TTC") and/ or the observed flow data for each of the HQ's external interfaces during the most recent historic period (January 2016 through December 2016).
- The CONE for the new HVDC transmission line to ISO-NE is highly project specific and can vary significantly based on the route and the extent to which the line is buried. We estimated the CONE for the transmission line by adjusting the annual revenue requirement filed by the developers of the Northern Pass Transmission project ("NPT").[80]
- The HQ region may be capacity constrained during some of the winter months. During such periods, the cost of capacity in the HQ region is likely to depend on the price of capacity in neighboring areas where additional capacity could be exported from the HQ region given the available interface capabilities. We estimated the amount of capacity HQ might need to purchase for export over the new HVDC line to ISO-NE as the difference between HQ's forecasted internal capacity and the internal peak demand plus the capacity rating of the new HVDC line.[81]

80 The latest estimate for the development cost of the NPT line is \$1.6 billion. See http://www.nhbr.com/April-28-2017/Eversource-Hydro-Quebec-revenues-could-fall-short-in-Northern-Pass-first-year/). In addition, TransEnergie is developing a 49 mile line to deliver power from the Des Cantons substation in Quebec to the US-Canadian border. See http://www.northernpass.us/assets/filings/Volume%20I/Northern%20Pass%20Transmission%20LLC%20Public%20Service%20of%20New%20Hampshire%20NH%20SEC%20Application%20for%20a%20Certificate%20for%20Site%20and%20Facility%20Executive%20Summary.pdf.

81 See 2016 LTRA, available at http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2016%20Long-Term%20Reliability%20Assessment.pdf.

E. Assessment of Fuel Availability during Severe Winter Conditions

Our estimates for the supply and demand for gas and oil for electric generation during two weeks of severe winter conditions are based on the following assumptions:

- *Availability of Pipeline Gas* – We estimated the availability of pipeline gas for electric generation by assuming that the gas system conditions observed during 15th-28th February 2015 are representative of the conditions that the ISO will need to plan for in the future years. In other words, we assumed that the pipeline gas available for electric generation will be similar to the amount used by generators during the historical two week period. For future years, we incorporated the following pipeline additions: (a) Algonquin Incremental Market (0.34 Bcf/ day), (b) Atlantic Bridge (0.13 Bcf/ day), (c) Connecticut Expansion of Tennessee Gas Pipeline (0.07 Bcf/ day), and (d) Continent to Coast (0.11 Bcf/ day).[82]
- *LNG Capability* – We assumed a maximum LNG send out capability of 1.67 Bcf/ day that is comprised of the sum of capabilities of the Distrigas, Canaport and Exelerate facilities. This is in addition to the 0.3 Bcf/ day of the Distrigas facility that supplies LNG to the Mystic units.[83]
- *Oil Inventory* – We assumed the total oil inventory to be similar to the observed level at the beginning of the historical two week period (4.5 million barrels). We adjusted this value for future years based on the tank sizes of the units that retired or enter service.[84]
- *Growth in Core Demand* – We adjusted down the amount of gas available for electric generation based on the growth in the core demand for gas in New England and portions of Eastern New York (total of ~5.1 Bcf/ day during 15th-28th February 2015). We assumed that the core demand will grow from the levels observed during February 2015 at the rate of 1.4 percent per year.
- *Gas and Oil Demand for Electric Generation* – We estimated the MWh demand for gas and oil generation for each year as the total MWh generated by gas and oil units in the historical two week period adjusted for the unit retirements. We converted the demand for electric generation (in MWh) to the demand for fuel from electric generation in future years by allocating fuel to units in the order of their heat rates. Major retirements we considered in our analysis include: Brayton Point (coal and oil steam turbines), Pilgrim (single-unit nuclear facility), all coal units, and 1.3 GW of oil steam turbine capacity.

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82 See presentation "Forecast of Near-term Natural Gas Infrastructure Projects" by Kevin Petak of ICF International at December 14th, 2016 Planning Advisory Committee meeting.

83 See slides 38-41 of presentation "December 14th, 2016 Planning Advisory Committee meeting." by Mark Babula at December 14th, 2016 Planning Advisory Committee meeting.

84 See slide 13 of presentation "Winter 2014/15 Review" by William Callan at June 29th, 2015 Electric/Gas Operations Committee (EGOC) Teleconference.

F. Potential Subsidized Entry through 2025/26

We estimate the capacity values of the potential subsidized entry that is driven by the currently known state initiatives. Our estimates shown in Table 1 are based on the following assumptions:

- Capacity for the Multi-State Clean Energy Solicitation is based on projects selected in October 2016, assuming 12 percent summer capacity value for wind and 43 percent summer capacity value for solar PV projects. Capacity for the Connecticut solicitation is estimated by applying a capacity value of 20 percent for the total nameplate capacity specified in the notice issued by DEEP in October 2016.
- The values shown for the RPS standard are based on the 2025 results of Scenario 1 from ISO-NE 2016 Economic Study. We reduce the required amount of renewables to meet RPS by actual entry from renewables in FCA-11 and by the offshore wind assumed to enter by 2025. We assume that resources required for RPS will enter at a uniform rate over the next five FCAs, but recognize that lumpy entry could create larger market issues.
- Massachusetts legislation (Section 83D of An Act Relative to Energy Diversity) signed in August 2016 requires the EDCs to enter into long term contracts by the end of 2022 for 9.45 TWh of clean energy (from a combination of firm service hydro resources and new Class I RPS-eligible resources). The new HVDC transmission lines that enable large-scale import of hydropower from Canada are well-positioned to supply this energy. The solicitation for these resources is due by April 2017 and recent RFP timelines suggest 1-1.5 years to contract execution so we assume a delivery year of 2022/23. We also did not include potential procurements for meeting greenhouse gas (GHG) abatement targets because these procurements would similarly also be satisfied by the solicitations shown in Table 1.
- Massachusetts legislation (Section 83 C of An Act Relative to Energy Diversity) signed in August 2016 authorizes the EDCs to enter into cost-effective long term contracts with up to 1600 MW of offshore wind resources by June 30th, 2027. National Grid, Unitil Corp and Eversource have recently sought approval of a draft RFP that procures 400 to 800 MW of offshore wind resources. Given the requirement for cost-effective contracts, current interconnection queue projects, long development time and deadline for contracts, we assume that only a quarter of the authorized 1600 MW will enter by 2025. The CONE and ORTP consultants assumed that a similar amount of offshore wind resources will enter by 2027.